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

GREGORY W. SAID

Q. Please state your name and business address.

A. My name is Gregory W. Said and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company as the Manager of Revenue Requirement in the Pricing and Regulatory Services Department.

Q. Please describe your educational background.

A. In May of 1975, I received a Bachelor of Science Degree in Mathematics with honors from Boise State University. In 1999, I attended the Public Utility Executives Course at the University of Idaho.

Q. Please describe your work experience with Idaho Power Company.

A. I became employed by Idaho Power Company in 1980 as an analyst in the Resource Planning Department. In 1985, the Company applied for a general revenue requirement increase. I was the Company witness addressing power supply expenses.

In August of 1989, after nine years in the Resource Planning Department, I was offered and I accepted a position in the Company's Rate Department. With the Company's application for a temporary rate increase in 1992, my responsibilities as a witness were expanded. While I continued to be the Company witness concerning power supply expenses, I also sponsored the Company's rate computations and proposed tariff schedules in that case.

Because of my combined Resource Planning and Rate Department experience, I was asked to design a Power Cost Adjustment (PCA) which would impact customers' rates based upon changes in the Company's net power supply expenses. I presented my recommendations to the Idaho Public Utilities Commission in 1992 at which time the Commission established the PCA as an annual adjustment to the Company's rates. I sponsored the Company's annual PCA adjustment in each of the years 1996 through 2003.

In 1996, I was promoted to Director of Revenue Requirement and in 2002 I was promoted to Manager of Revenue Requirement. I have managed the preparation of revenue requirement information for regulatory proceedings since 1996.

Q. What topics will you discuss in your testimony in this proceeding?

A. I will discuss changes in the Company's normalized power supply expenses since the Company's last general rate case, the impact of those changes on the Company's future Power Cost Adjustment (PCA) computations, and cloud seeding investment and expenses contained in the Company's computation of revenue requirement. I will also discuss the determination of imputed revenues associated with certain transmission and distribution plant additions included as annualizing and known and measurable adjustments within Ms. Schwendiman's computation of the current Idaho Power revenue requirement. Finally, I will discuss the major components in the Company's revenue requirement that have changed from currently approved levels.

Q. Please define the term "power supply expenses" as the Company and the Commission have used the term historically.

A. The Company and the Commission have traditionally used the term "power supply expenses" to refer to the sum of fuel expenses (FERC accounts 501 and 547) and purchased power expenses (FERC account 555) excluding expenses due to purchases from PURPA qualifying facilities (QF) minus surplus sales revenues (FERC account 447). For ratemaking purposes, QF expenses have been quantified separately from other power supply expenses and are treated as fixed inputs to power supply modeling rather than variable outputs.

Q. How are power supply expenses "normalized" for ratemaking purposes?

A. Power supply expenses are determined for each water condition dating back to 1928. In this case, 78 water conditions have been evaluated. The average of the power supply expenses over the range of hydro conditions is considered “normal” or representative of the possible circumstances the Company might encounter for ratemaking purposes. The Idaho Public Utilities Commission first adopted this method of averaging a representative range of power supply expenses associated with multiple water conditions to determine normalized power supply expenses in 1981.

Q. Have you supervised the preparation of normalized power supply expense modeling to reflect the current test year 2005 characteristics?

A. Yes. Under my supervision and at my request, a power supply simulation that is representative of the test year 2005 power supply expenses associated with 78 separate water conditions was prepared. This year the analysis includes water conditions corresponding to years 1928 through 2005. The average of the expenses related to each of the 78 water conditions represents the normalization of power supply expenses.

Q. Have you supervised the preparation of an exhibit to demonstrate the normalization of power supply expenses?

A. Yes. Exhibit 20 shows the results of the power supply expense normalization modeling for the test year 2005. Page 1 of Exhibit 20 shows the summary results containing the 78-year average power supply generation sources and expenses. Pages 2 through 79 contain results for each of the 78 individual water conditions 1928 through 2005.

Q. Please describe the change in the Company's system loads since the last general rate case, IPC-E-03-13.

A. The Company's 2003 annual normalized system load used in the IPC-E-03-13 general rate case and again in the IPC-E-05-10 Bennett Mountain case was 14.1 million megawatt-hours (MWh). The Company's 2005 annual normalized system load used in this case is 14.8 million MWh, approximately 5 percent higher.

Q. Please describe the increase in normalized power supply expenses that occurs with the 5 percent higher loads of 2005.

A. The Company's determination of normalized power supply expenses for the test year 2005 in this case is $52.0 million (Page 1 of Exhibit 20) compared to $47.2 million for test year 2003 as computed following the addition of the Bennett Mountain Power Plant to the Company system. This represents a 10.2 percent increase in power supply expenses from test year 2003 to test year 2005.

Q. How have market prices of energy changed in the last two years?

A. Market prices for energy are generally higher than market prices two years ago. In the IPC-E-03-13 case, monthly-modeled surplus sales prices fluctuated from $10 per MWh to $47 per MWh depending on market conditions. The annual fluctuation of modeled surplus sales prices in that case was from $16 per MWh to $36 per MWh. In this case, monthly-modeled surplus sales prices fluctuate from $13 per MWh to $56 per MWh. The annual fluctuation of modeled surplus sales prices in this case is from $23 per MWh to $47 per MWh. While the market prices for surplus sales have increased, the normalized volume of surplus sales has dropped from 3.0 million MWh to 2.6 million MWh due to load growth.

During conditions when the Company is a net purchaser of power, increases in market prices drive power supply expenses higher. In the IPC-E-03-13 case, monthly-modeled purchased power prices fluctuated from $8 per MWh to $50 per MWh depending on market conditions. Annual fluctuation of modeled purchased power prices in that case was from $8 per MWh to $45 per MWh. In this case, monthly-modeled purchased power prices fluctuate from $13 per MWh to $135 per MWh. The annual fluctuation of modeled purchased power prices in this case is from $18 per MWh to $95 per MWh. In addition to the increases in purchased power prices, the normalized volume of purchased power has also increased from 211 thousand MWh to 367 thousand MWh due to load growth.

Q. Given the increases in market prices, the decrease in surplus sales volumes and the increase in purchased power volumes, what is the current normalized net benefit of surplus sales revenues less purchased power expenses?

A. On a normalized basis, Idaho Power experiences a net benefit from secondary market transactions (i.e. surplus sales revenue minus purchased power expense). Even with load growth, purchased power growth, and surplus sales declines, higher market prices produce a greater net benefit today than two years ago. The current normalized net benefit of secondary market transactions is $51.0 million compared to Case No. IPC-E-03-13 benefits of $50.7 million.

Q. How have the modeled fuel expenses of the Company's coal-fired generating resources changed over the last two years?

A. The modeled fuel expense for coal-fired resources has increased by 3 percent from $95.1 million to $98.1 million primarily due to increases in the operational cost of Valmy.

Q. How have the modeled fuel expenses of the Company's gas-fired generating resources changed over the last two years?

A. Bennett Mountain expenses were not modeled in the IPC-E-03-13 case. Modeled fuel expenses for gas-fired generation has increased from $3.3 million to $4.9 million with the inclusion of the Bennett Mountain plant.

Q. What is the combined percentage increase in modeled fuel expenses (coal and gas) from the IPC-E-03-13 case to this case?

A. The combined percentage increase in modeled fuel expenses (coal and gas) from the IPC-E-03-13 case to this case is 4.4 percent.

Q. In light of load growth, market price changes and fuel expense changes, do you believe the Company's modeled power supply expenses represent a reasonable estimate of normalized power supply expenses?

A. Yes, I do.

Q. Please summarize the sources and disposition of energy as shown on page 1 of Exhibit 20.

A. From the summary information contained on page 1 of Exhibit 20 it can be seen that for the test year 2005, hydro generation supplies 8.7 million MWh while thermal generation supplies 7.2 million MWh (Bridger 5.0, Boardman 0.4, Valmy 1.8) from Company-owned generation resources. Danskin and Bennett Mountain, as peaking plants, operate intermittently, but offer significant contribution at important times when resources and purchases are inadequate to serve peak loads. Purchases of power come from three sources: market purchases, contract purchases other than QF and QF purchases. QF purchases are assumed at fixed normalized levels amounting to nearly 960 thousand MWh. Because the fixed QF purchases are fixed inputs to power supply modeling, they are not shown on the variable output summary, however, when combined with the market and other contract purchases, total purchases amount to 1.4 million MWh. As a result, hydro generation contributes approximately 50 percent (8.7 / 17.3) of the generation mix, thermal generation contributes approximately 42 percent (7.2 / 17.3) and purchases contribute approximately 8 percent (1.4 / 17.3). Of the over 17.3 million MWh consumed, 14.8 million MWh are utilized for system loads while over 2.5 million MWh are sold as surplus.

Q. Please describe the expense and revenue information associated with the normalized operation that you have just described as shown in Exhibit 20.

A. Exhibit 20 contains variable expense and revenue information limited to FERC accounts 501, Fuel (coal); 547, Fuel (gas); 555, Purchased Power; and 447, Sales for Resale. Hydro generation has no assumed fuel expense. Coal expenses of $98.1 million are comprised of Bridger at $62.5 million, Valmy at $30.1 million and Boardman at $5.5 million. Gas expenses amount to $4.9

million. Purchased power expenses not including QF amount to $25.7 million while surplus sales amount to $76.7 million. Altogether, net power supply expenses amount to $52.0 million (98.1 + 4.9 + 25.7 - 76.7).

Q. How do base level PCA expenses differ from test year power supply expenses?

A. Base level PCA expenses differ from test year power supply expenses in two ways. First, base level PCA expenses include QF expenses. Second, base level PCA expenses are determined for an April through March time frame rather than a calendar year. April represents the beginning of the runoff period that provides the basis for the PCA projection.

Q. What are the 2005 test year normalized QF expenses?

A. The 2005 test year normalized QF expenses amount to $54.6 million.

Q. How do 2005 test year normalized QF expenses compare to 2003 test year QF expenses?

A. The 2005 test year normalized QF expenses of $54.6 million are $8.2 million greater than the $46.4 million 2003 test year normalized QF expenses. In the last two years, 7 contracted QF projects with 26 MW of capacity have been added to the previous 69 projects.

Q. What is the base level of PCA expenses for test year 2005?

A. As I stated earlier in my testimony, the base level of PCA expenses is the sum of the normalized power supply expenses and normalized QF expenses. In this case, normalized power supply expenses amount to $52.0 million and normalized QF expenses amount to $54.6 million. The sum, $106.6 million, represents the new base PCA expense level.

Q. Have you supervised the preparation of an exhibit that shows the derivation of the appropriate new PCA regression formula to be used for projecting the next year's PCA expenses?

A. Yes. Exhibit 21 was prepared under my supervision to show the derivation of the new PCA regression formula.

Q. Please describe Exhibit 21.

A. Exhibit 21 consists of six columns at the top of the page. Column one shows the number of the observation from 1 to 77. Column 2 contains the PCA year corresponding to each observation; observation 1 is 1928, observation 2 is 1929, and so on through observation 77, which is 2004. Because the PCA year is for months April through March of the following year, there are only 77 observations instead of the 78 conditions represented in Exhibit 20. Column 3 contains the April through July runoff for each of the observation years 1928 through 2004. Column 4 contains the natural logarithm of the runoff value contained in Column 3. Column 5 contains the observed April through March annual power supply expense based upon data from Exhibit 20, but reflecting PCA totals rather than calendar year totals. Finally, Column 6 contains the regression predicted value of April through March annual power supply expenses.

To the right of the columns are summary output of certain regression statistics (such as r-square) and formula coefficients.

Q. Please describe the new PCA regression formula based upon Exhibit 21.

A. The basic PCA formula takes the following form: Annual PCA expense = C1 - C2 * ln (Brownlee runoff) + C3. The values of C1, C2 and C3 are constant with the only variable being Brownlee runoff. The equation without C3 is used to predict net power supply expenses and is the direct result of the regression analysis contained in Exhibit 21. The constant C1 represents the prediction of annual net power supply expense that would occur if there was zero April through July Brownlee runoff. The value of C1 is $1,944,927,036. In reality, the lowest April through July Brownlee runoff contained in the observations is 1.87 million acre-feet which occurred in the 1992 observation.

Because the regression provides a linear fit of a non-linear transformation, the value of C2 is somewhat difficult to explain. Observed Brownlee runoff data in acre-feet is first transformed by the natural logarithm function. For each unit increase in the natural logarithm of the Brownlee runoff data the projection of annual power supply expenses will be reduced by C2, which is $122,906,946. The average natural logarithm of Brownlee runoff values, based upon the observations contained in Exhibit 21, is 15.40. This value corresponds to a runoff of approximately 4.9 million acre-feet (e ^ 15.40 = 4,876,801 million acre-feet). With a runoff of 4.9 million acre-feet and a natural logarithm of 15.40, the projected net power supply expenses would be $52,160,068 ($1,944,927,036 - $122,906,946 * 15.40). An increase of 1 to the natural logarithm would result if the runoff was approximately 13.2 million acre-feet (ln(13,256,519) equals 16.40 which equals 15.40 + 1). With a runoff of 13,256,519 million acre-feet, the net power supply expenses would be $122,906,946 less than $52,160,068 making the projection of power supply expenses a negative $70,746,878 ($1,944,927,036 - $122,906,946 * 16.40).

The natural logarithms of observed Brownlee runoff ranged from 14.44 (1992 runoff) to 16.25 (1984 runoff). The difference, 1.81 (16.25 - 14.44), multiplied by $122,096,946 equals approximately $221 million, which represents the change in projected power supply expenses from the highest water case (1984) to the lowest water case (1992).

The value of C3 is $54,632,157, the normalized expense for QF. Because the normalized expense for QF is quantified separately from net power supply expenses it is added to net power supply expenses to determined the PCA expenses.

Q. What is the new PCA regression equation with values inserted for the constants?

A. The new PCA regression equation is:

Annual PCA expense = $1,944,927,036
- $122,906,946 * ln (Brownlee runoff)
+ $54,632,157.

Q. How does the range in projected power supply expenses from high condition to low condition resulting from this regression equation compare to the range of projected power supply expenses in the previous regression equation?

A. The predictions of power supply expenses based upon the regression observations contained in the previous regression analysis ranged by $131.5 million from the highest estimate to lowest estimate of power supply expenses compared to the current range of $221 million. Higher market prices introduce greater volatility in power supply expenses.

Q. Do you recommend any additional PCA computational changes with the establishment of the new PCA regression formula?

A. Yes. There are two PCA computational factors that need to be updated as a result of the current review of power supply expenses. First, for PCA projection calculations, a new normalized base PCA rate can be determined. Second, a new Idaho jurisdictional percentage can be determined.

Q. Have you supervised the development of an exhibit to determine the PCA computational factors you have just mentioned?

A. Yes, Exhibit 22 is a one-page exhibit detailing the appropriate computation of the PCA factors I have outlined.

Q. What is the first computation shown on Exhibit 22?

A. The first computation recaps the normalized PCA computation that I have discussed thoroughly in my testimony. The new normalized PCA expenses for 2005 test year amount to $106.6 million compared to the previous $94.1 million value for the 2003 test year.

Q. Please discuss the normalized Base PCA rate computation contained in Exhibit 22.

A. The computation of the normalized Base PCA rate is equal to the $106.6 million normalized PCA expenses be divided by the normalized system sales value of

13,497,550 MWh. The resulting PCA base rate is 0.7898 cents per kWh.

Q. Please discuss the Idaho jurisdictional percentage computation contained in Exhibit 22.

A. The Idaho jurisdictional firm load (13,950,521 MWH) divided by the system firm load number (14,819,152) results in an Idaho jurisdictional percentage of 94.1 percent.

Q. Has the Company filed an application (cloud seeding case) with the Idaho Public Utilities Commission requesting that cloud seeding program expenses be included in PCA computations on an on-going basis?

A. Yes.

Q. How does the cloud seeding case application affect the PCA computations you have described in this case?

A. First, cloud seeding expenses are booked in FERC account 536, Water for Power, which is not currently a PCA account. If the Company request to include cloud seeding program expenses in PCA computations is approved, base normalized PCA expenses will increase from $106.6 million to $107.6 million to reflect the $1,004,538 of cloud seeding expenses anticipated to be booked annually in FERC account 536 and included in the test year computations Ms. Schwendiman is presenting in this case. However, consistent with the cost benefit study presented by Mr. Riley in the cloud seeding case, the Company and its customers should also see benefits amounting to $1.7 million (1.7 benefit to cost ratio times $1.0 million of annual expense) thereby reducing the normalized PCA expenses to $105.9 million. As a result the Base PCA rate computation would become equal to the $105.9 million normalized PCA expenses divided by the normalized system sales value of 13,497,550 MWh resulting in a PCA base rate of 0.7846 cents per kWh.

Q. Does the cloud seeding case also affect the revenue requirement determination in this case?

A. Yes. In this case, based upon my instructions, Ms. Schwendiman included cloud seeding expenses in the test year, 2005. However, I did not instruct her to include any "assumed" revenue offsets to those cloud seeding expenses because any such revenue offsets would be reflected as reductions in power supply expenses that would automatically be reflected in the Power Cost Adjustment and flow through (90 percent) to customers. As a result, customers would pay for cloud seeding expenses through base rates and receive cloud seeding benefits through the PCA. It would not be appropriate for customers to receive a double benefit by reducing the base rate revenue requirement as well. However, with the Company request to track cloud seeding expenses and as well as the cloud seeding benefits through the PCA, it is now appropriate to include a base rate benefit in the Company's revenue requirement as well as its PCA base rate level. If the Company's cloud seeding case application to include cloud seeding expenses in the Company's PCA is approved, the Company's revenue requirement as presented in this case is overstated by $1.6 million ($1.7 million system cloud seeding benefit * .941, the Idaho jurisdictional share). The full, anticipated, normalized Idaho jurisdictional cloud seeding benefits would flow through to the Company's customers.

Q. Included in Ms. Schwendiman's computations of revenue requirement are computations of imputed revenues associated with the addition of distribution and transmission facilities included in either the annualizing adjustments or known and measurable adjustments. Why did you instruct Ms. Schwendiman to include these imputed revenues?

A. The Commission in Order No. 29505 issued in Case No. IPC-E-03-13 stated that "it is critical to match revenues and expenses to these plant additions" when referring to known and measurable additions. The Commission used a proxy for additional revenues stating that the Company had "not adequately quantified" such additional revenues. In its filing in this Case the Company has included a quantification of revenues associated with both annualizing and known and measurable adjustments to transmission and distribution plant.

Q. Please describe the Company's method of quantifying revenues associated with the annualizing and known and measurable adjustments to transmission and distribution plant.

A. In order to estimate the additional revenues that the Company would receive as a result of adding the transmission and distribution plant reflected in the annualizing and known and measurable adjustments, I requested the preparation of Exhibit 23 which shows the planned use of those additional transmission and distribution facilities by year end 2006. Based upon the anticipated loads on those facilities by year end 2006 (119,253.4 MWh) and the system average revenue per MWh ($15.42 per MWh), the imputed revenue associated with the annualized and known and measurable transmission and distribution additions is $1,661,587 for the Idaho jurisdiction. This is approximately 31.9 percent of the Idaho jurisdictional revenue requirement resulting from these additional investments.

Q. How does this 31.9 percent imputation of revenue compare to the Commission imputation of revenue from similar assets in Case No. IPC-E-03-13?

A. The Commission imputation of revenue was approximately 37.7 percent of the transmission and distribution revenue included in the annualizing and known and measurable adjustments. The Company methodology presented here is consistent with the value used by the Commission in that case.

Q. Please summarize why Idaho Power Company is requesting a rate increase.

A. The fundamental reason that Idaho Power requires a rate increase is that growth in Company revenue is not currently keeping pace with growth in Company expenses and the Company's need to earn a reasonable return on its rate base investment.

Q. Given the 2003 test year and the inclusion of Bennett Mountain in the Company's rate base, what was the Company's Idaho jurisdictional sales and wheeling revenue requirement in 2004?

A. Given a 2003 test year and after the addition of the Bennett Mountain plant, the Idaho Public Utilities Commission established rates it judged to be sufficient to generate $533.0 million of annual revenue in Idaho Power's Idaho jurisdiction.

Q. Based upon 2005 test year Idaho jurisdictional loads, what is the Idaho jurisdictional sales and wheeling revenue that is currently received?

A. The 2005 test year Idaho jurisdictional sales and wheeling revenue, not including imputed revenue from annualizing and known and measurable adjustments, is $561.4 million, an increase of $28.4 million over previous levels.

Q. Using the 2003 test year and the inclusion of Bennett Mountain in the Company's rate base, what were the Company's Idaho jurisdictional expenses?

A. Given a 2003 test year, the Company's Idaho jurisdictional expenses, net of revenue credit offsets, were $413.9 million after the addition of the Bennett Mountain plant.

Q. Based upon 2005 test year Idaho jurisdictional loads and investment levels, what is the Company's current level of Idaho jurisdictional expenses?

A. The 2005 test year Idaho jurisdictional expenses, net of revenue credit offsets, is $466.8 million, a growth in expense of $52.9 million over the prior period.

Q. What was the Idaho jurisdictional level of rate base for the 2003 test year after the addition of Bennett Mountain?

A. The Idaho jurisdictional level of rate base for the 2003 test year, after the addition of Bennett Mountain, was $1.517 billion.

Q. What is the current level of Idaho jurisdictional rate base?

A. The current level of Idaho jurisdictional rate base is $1.654 billion, a growth of $137 million over the prior period.

Q. Using Mr. Gribble's recommended rate of return, what is the additional return required based upon the growth of $137 million in rate base?

A. The Company's requested Idaho jurisdictional return of $139.2 million is $20.2 million greater than the 2003 test year return of $119.1 million.

Q. What is the Company's Idaho jurisdictional revenue deficiency based upon these 2005 test year amounts?

A. Given that expenses have grown by $52.9 million and given that the need for return on investment has grown by $20.2 million, the Company's Idaho jurisdictional revenue requirement has grown by $73.1 million ($52.9 million + $20.2 million). Idaho jurisdictional revenues have grown by $28.4 million leaving a revenue deficiency of $44.7 million ($73.1 million - $28.4 million). Ms. Schwendiman presents the detailed information regarding the Company's Idaho jurisdictional revenue requirement and revenue deficiency.

Q. Is load growth currently causing a revenue deficiency for Idaho Power Company?

A. Yes. Idaho Power is currently experiencing a period of high growth that requires significant additional electric infrastructure investment and expense. The incremental costs of new facilities necessary to serve additional loads are significantly higher than the incremental revenue the Company is receiving from additional sales of electricity. This occurs because sales of electricity are priced at embedded costs rather that incremental costs.

Q. Does that conclude your testimony?

A. Yes.