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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION FOR APPROVAL OF CHANGES TO ITS POWER COST ADJUSTMENT ("PCA") MECHANISM	)	CASE NO. IPC-E-08-19

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 Director of State Regulation 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. I continue to supervise PCA-related regulatory filings.

In 1996, I was promoted to Director of Revenue Requirement. I have managed the preparation of revenue requirement information for regulatory proceedings since that time.

Earlier this year, I was promoted to Director of State Regulation adding the area of Rate Design to my responsibilities.

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

A. My testimony in this proceeding is intended to sponsor and support the Stipulation regarding Idaho Power Company's Power Cost Adjustment ("PCA") mechanism ("Stipulation"), and to urge the Commission to adopt the Stipulation without material change or condition. The Stipulation is Exhibit No. 1 to my testimony. In my testimony, I will discuss the workshop and settlement discussions leading up to the Stipulation signed by the Company, the Commission Staff, the Industrial Customers of Idaho Power, the Idaho Irrigation Pumpers Association, the United States Department of Energy, and Micron Technology. These entities are collectively referred to in my testimony as "the Parties." I will discuss each of the issues addressed in the Stipulation focusing on the merits of the Stipulation from the Company's perspective and I will discuss the benefits that customers will receive as a result of PCA changes recommended in the Stipulation.

Q. Could you briefly describe the PCA and summarize the reasons underlying Idaho Power's support for the adjustments to the PCA methodology set out in the Stipulation?

A. Yes. Idaho Power, like other regulated public utilities, is compensated for historically "normal" power supply expenses through its base electricity rates established by the Commission in general rate cases. Because the Company's actual power supply expenses have significant variation from year to year while the power supply expense component embedded in base rates is static, the Commission has adopted a PCA that is intended to mitigate, but not entirely eliminate, the impact of power supply expense variability on the Company's earnings. Net power supply expenses vary from year to year in inverse correlation to the amount of electricity generated by the Company's hydro generation facilities.

Although the PCA benefits the Company by reducing the variability associated with power supply expenses, certain elements of the current PCA methodology, such as the "sharing methodology" and the "load growth adjustment rate" ("LGAR"), have significantly impaired the Company's ability to earn its authorized rate of return. Two primary conditions in recent years - sustained low water (and resultant low hydro production) and sustained system-wide increased demand for electricity - have significantly amplified the adverse effect of these elements of the PCA methodology on the Company's earnings and cash flow.

Q. How do reduced earnings and cash flow affect the Company and its customers?

A. The Company's inability to recover its authorized rate of return has, in turn, resulted in deterioration of the Company's credit quality as measured by the national credit rating agencies. Between 2000 and 2007, the Company's Standard & Poor's credit rating has dropped four grades, from a rating of "A+" to a rating of "BBB." The credit agencies and financial markets attribute this drop directly to the PCA's sharing formula and LGAR.

This lessening of the Company's creditworthiness has direct, adverse financial consequences not just for the Company's shareholders but also for its customers. Impaired financial strength reduces share value to the detriment of shareholders. Moreover, a lower credit rating increases the interest cost of debt, which is borne by the Company's customers. The cumulative additional interest expense of a $100 million, 30-year bond issued by a "BB" rated utility is approximately $60 million greater than a comparable bond issued by an "A" rated utility.

Q. Why is the Company credit rating important to customers?

A. The Company is undertaking an infrastructure build-out that is unprecedented since its construction of the Hells Canyon complex. The Company currently expects to spend $900 million in construction expenditures in the immediate future (2008 to 2010), excluding any expenditures for a nominal 250-MW combined cycle combustion turbine expected to be in service as early as 2012. Significant additional capital expenditures are expected thereafter. Financing this new infrastructure will be at a much greater cost to the Company's shareholders and customers if its credit ratings remain impaired by the current application of the PCA's methodology.

Q. Please describe the PCA workshop/settlement process leading up to the Stipulation.

A. As per Commission Order No. 30563 issued in Case No. IPC-E-08-07, Idaho Power Company held a PCA Issues Workshop on July 30, 2008. At that workshop, the Company identified five PCA issues that it was hopeful the interested parties in the Company's PCA proceeding would agree merited modification on a going-forward basis. The five issues were:

1. The PCA sharing ratio
2. The Load Growth Adjustment Rate
3. The annual PCA forecast
4. Third-party transmission expenses
5. The Power Supply Expense Distribution for Deferral purposes.

The workshop was attended by members of the Commission Staff, representatives for the Industrial Customers of Idaho Power, and representatives for Micron Technology. Representatives for the United States Department of Energy participated via telephone.

At the end of the first workshop, Micron suggested adding a sixth issue to address PCA rate spread and revenue allocation to customer classes. The parties agreed that all of the issues identified merited discussion and agreed that further discussions should be considered settlement discussions rather than merely workshops.

Subsequently, two settlement meetings were conducted on August 13, 2008, and September 3, 2008, to further discuss the identified issues. The Idaho Irrigation Pumpers Association, which had not participated in the workshop, participated by phone in each of the settlement meetings.

Following the September 3rd settlement meeting, the Company worked with the parties to prepare the settlement Stipulation filed in this case. All participating parties have agreed to and signed the Stipulation. It is my understanding that the Commission Staff will file testimony supporting the Stipulation.

Q. Please discuss the agreed-upon change to the PCA sharing ratio.

A. The current PCA sharing ratio for non-PURPA power supply expenses is 90 percent customer, 10 percent Idaho Power Company. What that means is that customers are responsible for 90 percent of power supply expense increases above levels included in base rates or that they receive 90 percent of power supply expense decreases below levels included in base rates.

The historic rationale supporting the 90/10 sharing ratio has been that it aligns the Company's interests with those of its customers to assure that the Company makes prudent decisions regarding its power supply expenses. The stated reason for the 90/10 percent sharing ratio in the PCA was to incent the Company to make wise decisions with regard to the purchase or sale of energy because the Company was "on the hook" for 10 percent of expenditures. Several things have changed since the adoption of the current 90/10 sharing ratio that necessitate its change. These changes include: (1) a substantial increase in the magnitude and volatility of power supply expenses; (2) development of the Company's Risk Management Policy; (3) the shift of the Federal Energy Regulatory Commission ("FERC") away from setting wholesale rates based on cost-of-service and towards wholesale rates based on market prices; and (4) reduced base flows in the Snake River system, combined with continuous years of sustained drought and sustained system load growth.

The combined impact of these changes has substantially increased the magnitude and volatility of power supply expenses since the original implementation of the PCA.

Q. Can you provide an example of this increased magnitude and volatility?

A. Volatility in power supply expenses from high to low water conditions based upon modeled scenarios was slightly over $100 million in 1992 when the PCA was first implemented. Volatility in modeled power supply expense scenarios is now over $330 million. When the 90/10 sharing ratio was initially established, the 10 percent component represented approximately 50 basis points of the Company's earnings. Today, because of the many changed conditions referenced below, the 10 percent sharing ratio represents more than 100 basis points of Company earnings. Modifying the sharing ratio to 95/5 simply restores the Company's risk parameter to approximately 50 basis points of earnings.

Q. How has the development of the Company risk management policy affected net power supply expense volatility?

A. To address power supply expense volatility, the Company worked closely with its customers to develop the Company's Risk Management Policy. The Risk Management Policy establishes a prescriptive buying and selling policy. Before the energy crisis of 2000 and 2001, the Company exercised considerable discretion with regard to the advance purchase of energy for anticipated future deficiencies or the advance sale of energy for anticipated future surpluses. Following the energy crisis, the Commission directed the Company to adopt a prescriptive Risk Management Policy to mitigate risk associated with hydro and market price variability. The risk management policy is conservatively biased to provide adequate resources to meet anticipated demand and to protect against extremes in market electricity prices. As a result, the process is now far more prescriptive in nature than when the PCA was adopted. With a prescriptive buying and selling policy driving the vast majority of the Company's energy purchases and sales, the need for the incentive provided by the sharing methodology is reduced significantly, if not eliminated entirely.

Q. How have the parties to the Stipulation agreed to address the sharing ratio to address volatility?

A. Given the changes in power supply expense volatility and the prescriptive nature of the Company's Risk Management Policy, the parties to the Stipulation agree that shifting the sharing ratio to 95 percent customer, 5 percent Idaho Power Company is reasonable. As a result, customers will be responsible for 95 percent of power supply expense increases above levels included in base rates or will receive 95 percent of power supply expense decreases below levels included in base rates. Conversely, the Company will have only 5 percent exposure to the higher power supply expense volatility rather than 10 percent. The Parties agree that this PCA sharing ratio change is fair, just, and reasonable, and aligns with the original intent of the PCA sharing methodology.

Q. Please discuss the stipulated change in the Load Growth Adjustment Rate.

A. The Load Growth Adjustment Rate ("LGAR") has been a topic of frequent and divergent debate over the years. Rather that rehashing the discussions of the past, I will focus on the stipulated change to the LGAR. The Parties agree that the intent of the LGAR is to eliminate recovery of that component of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer usage patterns. The agreed-upon method for computing the LGAR recognizes generation-related revenue that results from the growth drivers that I have just described and will be quantified at the end of each general rate case. The stipulated LGAR methodology consists of three components, a return component, expense component, and a revenue component of the production related rate base. An example of the agreed-upon LGAR computation is contained in Exhibit A to the Stipulation. All Parties have agreed that the calculation set forth in Exhibit A to the Stipulation is fair, just, and reasonable and accomplishes the stated intent of the LGAR. Acceptance of the LGAR computation contained in the Stipulation will resolve a long-standing dispute to the satisfaction of all Parties to the Stipulation.

Q. Please discuss the agreed-upon change in the PCA forecast methodology set out in the Stipulation.

A. Since the inception of the PCA, the PCA forecast methodology has been based upon a single input. Each April the National Weather Service's Northwest River Forecast Center ("NWRFC") makes a stream flow forecast upon which the PCA forecast is based. Projected expenses are calculated by using a natural logarithmic function of a single variable - projected April through July Brownlee reservoir inflows. Variations in this forecast from actual expenditures included in rates are collected the following year. Thus, the more accurate the forecast is, the smaller the amount that accrues in the deferral for inclusion with the following year's PCA rates during the "true-up." The better the forecast, the smaller the subsequent year true-up amount. All parties agree that the best possible forecast should be utilized. All parties agree that the Company's Operation Plan is the best available forecast of power supply expenses.

Q. Please discuss the parties' agreement to include third-party transmission expenses in PCA computations.

A. Third-party transmission expenses are incurred by the Company in order to facilitate either purchases of energy from or sales of energy to various trading hubs. As an example, a purchase of energy from the Mid-C trading hub requires wheeling the power to the Company's system and, conversely, the sale of energy at the Mid-C hub requires wheeling the power from the Company's system to the Mid-C hub. Variability of third-party transmission wheeling expense is directly related to the volumes of purchases from and sales of energy to entities that are some distance from the Company's service territory boundaries. The Parties agree that third-party transmission expenses are directly related to power supply expenses and should therefore reasonably be included in PCA computations.

Q. Please discuss the stipulated change in the Power Supply Expense Distribution for PCA true-up computations.

A. Historically, power supply expenses were reported throughout the year using an AURORA-based distribution. In order to provide the financial community more transparent and understandable financial communications, the parties agree that for purposes of PCA deferral reporting, the Base Net Power Supply Expenses will be distributed to monthly values based upon a monthly revenue shape. This adjustment will not affect the total PCA year calculation of the deviation between actual and Base Net Power Supply Expenses, but will improve comparability between interim and annual financial reporting periods.

Q. Please comment on the discussion in the Stipulation regarding rate spread and revenue allocation within PCA computations.

A. The Parties recognize the PCA rates are implemented on a 100 percent energy basis. The Parties agree that rate spread and revenue allocations will be examined as part of the current general rate case and that such examination may suggest changes to PCA rate design as well. The Parties agree to a reexamination of PCA rate design following the general rate case.

Q. Please describe the benefits that Idaho Power Company's Idaho jurisdictional customers will receive as a result Commission approval of this Stipulation.

A. I believe that Idaho Power Company's Idaho jurisdictional customers will benefit from each of the areas of agreement contained in the Stipulation.

First, as a result of the change in the PCA sharing ratio, customers will get a more accurate picture of their true power supply related cost-of-service as it fluctuates with water and market conditions. By adjusting the sharing ratio to 95%/5% from 90%/10%, the intent of the sharing ratio's impact on the Company will be more closely realigned to the impact envisioned at the time the PCA was initiated.

Second, as a result of the stipulated change to the LGAR rate determination, customers are assured that double recovery of power supply expenses will not occur and a major concern of the financial community will be mitigated. This should benefit customers in both the short and long runs.

Third, as a result of the stipulated change to the PCA forecast methodology, PCA forecasts should be improved from PCA forecasts of the past. With more accurate forecasts, true-ups will be reduced making annual changes to PCA rates more understandable to customers. PCA rates should be primarily the result of the upcoming year's power supply expenses rather than a result of truing-up the previous year's power supply expenses.

Fourth, including third-party transmission expenses in PCA computations assures alignment of cost considerations to the benefit of both the Company and its customers.

Fifth, utilizing a power supply expense distribution based upon a revenue shape, for deferral purposes, provides for more understandable quarterly earnings statements. Customers benefit when the financial community understands key drivers of the Company's earnings.

Finally, the totality of these changes to the PCA should help the Company retain or improve its credit ratings. Both the Company and its customers benefit from favorable credit ratings from the national credit rating agencies, especially given the large capital expenditures that are planned and necessary in the near future.

Q. Given the customer benefits to be derived from Commission approval of the Stipulation, what is your recommendation to the Commission?

A. I recommend that the Commission find the Stipulation to be in the public interest and approve the same without change or conditions. I further recommend that the Commission direct the Company to implement changes to the PCA consistent with the terms of the Stipulation.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-08-19

IDAHO POWER COMPANY

SAID, DI
TESTIMONY

EXHIBIT NO. 1

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION FOR APPROVAL OF CHANGES TO ITS POWER COST ADJUSTMENT ("PCA") MECHANISM	)	CASE NO. IPC-E-08-19 STIPULATION

This stipulation ("Stipulation") is entered into by and among Idaho Power Company ("Idaho Power" or the "Company"), the Staff of the Idaho Public Utilities Commission ("Staff"), the Idaho Irrigation Pumpers Association, Inc. ("IIPA"), the Industrial Customers of Idaho Power ("ICIP"), Micron Technology, Inc. ("Micron"), and the United States Department of Energy ("DOE"). These entities are collectively referred to as the "Parties."

I. INTRODUCTION

1. The terms and conditions of this Stipulation are set forth herein. The Parties agree that this Stipulation represents a fair, just and reasonable compromise of the issues raised in this proceeding and that this Stipulation is in the public interest. The Parties maintain that this Stipulation and its acceptance by the Idaho Public Utilities Commission ("IPUC" or the "Commission") represent a reasonable resolution of multiple issues identified in this matter. The Parties, therefore, recommend that the Commission, in accordance with RP 274, approve the Stipulation and all of its terms and conditions without material change or condition.

II. BACKGROUND

2. In the settlement Stipulation for Idaho Power's 2007 general rate case, the Parties agreed that they would "make a good faith effort to develop a mechanism to adjust or replace the current Load Growth Adjustment Rate (LGAR) to address cost of serving load growth between rate cases." Stipulation at p.4, Case No. IPC-E-07-08. In the Commission's final Order for the 2008-2009 Power Cost Adjustment ("PCA") case the Commission stated:

> With respect to further evaluation of the PCA mechanism, Staff, Idaho Power, and the Irrigators all proposed workshops to address issues such as sharing methodology, forecasting methodology, the distribution of power cost deferrals, and load growth adjustment rates. We support these proposals and direct Idaho Power to schedule such workshops as soon as practicable.

Order No. 30563 at p.6-7, Case No. IPC-E-08-07.

3. Idaho Power held three workshops where issues related to the PCA mechanism were discussed. All of the Parties to this Stipulation participated in the

workshops. The first workshop, held on July 30, 2008, introduced the issues. The second and third workshops, held on August 13, and September 3, 2008, respectively, consisted of continued dialogue on the relevant issues, as well as discussions regarding the consensus of the Parties, which is represented by the terms of this Stipulation.

4. Idaho Power, like other regulated public utilities in Idaho, is compensated for historically "normal" power supply expenses through its base electricity rates established by the Commission in general rate cases. Because the Company's actual power supply expenses have significant variation from year to year, while the power supply expense component embedded in base rates is static, the Commission has adopted a PCA that is intended to mitigate, but not entirely eliminate, the impact of power supply expense variability on the Company's earnings. Net power supply expenses vary from year to year in inverse correlation to the amount of electricity generated by the Company's hydro generation facilities.

Although the PCA benefits the Company by reducing the variability associated with power supply expenses, certain elements of the PCA methodology, such as the "sharing methodology" and the "load growth adjustment rate" can reduce the Company's ability to earn its authorized rate of return. Two primary conditions in recent years – sustained low water (and resultant low hydro production) and sustained system-wide increased demand for electricity – have amplified the adverse effect of these elements of the PCA methodology on the Company's earnings and cash flow.

In the workshops, Idaho Power presented evidence that the Company's inability to recover its authorized rate of return is one of the reasons for the deterioration of the Company's credit quality as measured by the national credit rating agencies over the last several years. The evidence presented by the Company included statements from analysts noting that this summer the Company's inability to fully recover power supply expenses, coupled with capital expansion outlays, have gradually whittled away the Company's financial strength. These factors contributed to Standard and Poors recent downgrade of IDACORP and Idaho Power debt and to Moody's placement of IDACORP and Idaho Power debt on watch for possible downgrade from its current ratings level. Deterioration of the Company's credit rating has increased the cost to access capital and resulted in increased costs to customers.

5. Based upon the discussions and consensus among the Parties at the workshops, as a compromise of the positions in this case, and for other consideration as set forth below, the Parties agree to the following terms:

III. TERMS OF THE STIPULATION

6. Sharing Methodology. The PCA Sharing Methodology establishes a fixed allocation of non-PURPA power supply expenses between customers (90%) and shareholders (10%). The Parties agree to change the current 90%/10% Sharing Methodology to 95%/5%. When the 90%/10% Sharing Methodology was initially established, the 10% component represented approximately 50 basis points of the Company's earnings. Today, because of the many changed conditions referenced below, the 10% sharing component represents more than 100 basis points of Company earnings. Modifying the Sharing Methodology to 95%/5% restores the Company's risk parameter to approximately 50 basis points of earnings.

The historic rationale for the 90%/10% sharing has been to assure that the Company's interests are aligned with those of the customer, and that the Company makes prudent decisions regarding its power supply expenses. The stated reason for the 90%/10% sharing ratio in the PCA was to incent the Company to make wise decisions with regard to the purchase or sale of energy because the Company was "on the hook" for 10% of expenditures. Two things have changed since the adoption of the Sharing Methodology that necessitate its change: (1) a substantial increase in the magnitude and volatility of power supply expenses driven by market and fuel price volatility coupled with increasing loads and (2) development of the Company's Risk Management Policy.

The more significant change is the fact that the magnitude and volatility of power supply expenses have increased substantially since the initial implementation of the PCA. Volatility from high to low water conditions has increased from the expectation of slightly over $100 million in 1992 to over $330 million based upon modeled scenarios. This large increase in magnitude and volatility is primarily attributable to a fundamental change in market conditions and increased loads.

The other significant change directly related to supporting a change in the Sharing Methodology is the development of the Company's prescriptive "Risk Management Policy." Before the western energy crisis of 2000 and 2001, the Company exercised considerable discretion with regard to the advance purchase of energy for anticipated future deficiencies or the advance sale of energy for anticipated future surpluses. As a direct result of high PCA rates during the energy crisis, the Commission directed the Company, Commission Staff, and customer groups to formulate a Risk Management Policy to mitigate risk associated with hydro and market price variability. The Risk Management Policy is conservatively biased to provide adequate resources to meet anticipated demand and to protect against extremes in market electricity prices. As a result, the market purchase and sale process is now far more prescriptive in nature than when the PCA was adopted. With a prescriptive buying and selling policy driving the vast majority of energy purchases and sales, the need for the incentive provided by the Sharing Methodology is reduced.

The Parties agree that given the change in circumstances since the PCA was initially instituted, changing the 90%/10% Sharing Methodology to 95%/5% is fair, just, and reasonable, and aligns with the original intent of the Sharing Methodology. The Parties agree that the new 95%/5% Sharing Methodology should be effective on the first day of the month following Commission approval of this Stipulation.

7. <u>Load Growth Adjustment Rate</u>. The LGAR is an element of the current PCA formula intended to eliminate recovery of that component of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer usage patterns. The Parties agree to calculate the LGAR using three components, a return component, an expense component, and a revenue component of the production related rate base. This methodology recognizes the generation-related revenue that will be provided through base rates by load growth. The LGAR components used in the methodology will be updated with other PCA inputs at the conclusion of a general rate case. An example of the agreed upon calculation is shown in Exhibit A to this Stipulation.

Incident to the PCA true-up, LGAR is currently calculated by comparing actual system load with normalized system load established in the most recent general rate case. The difference in megawatt hours is divided by two and multiplied by $62.79.

When actual load is greater than normalized base system load, the Company refunds the difference (subject to the sharing formula) to the customer and records increased PCA expense. Because normalized system load is determined in a general rate case using a historical test year, and because the Company continues to experience system wide growth, the LGAR has consistently had an adverse effect on the Company's earnings.

The initial LGAR rate was $16.84 per MWh. The current effective LGAR from the IPC-E-07-0-8 rate case is $31.40. The previous determination from the IPC-E-06-08 LGAR case was $29.41 per MWh. The LGAR calculation, using the methodology agreed to by the Parties in this Stipulation, along with the filed data from the IPC-E-08-10 rate case is $28.14 per MWh, as shown in Exhibit A. The Parties agree that the calculation set forth in Exhibit A is fair, just, and reasonable. The Parties agree that the new LGAR methodology should become effective when its components are established and new rates implemented as a result of the IPC-E-08-10 general rate case.

8. <u>The Forecast</u>. Each April the National Weather Service's Northwest River Forecast Center ("NWRFC") makes a stream flow forecast upon which the PCA forecast is based. Projected expenses are calculated by using a natural logarithmic function of a single variable – projected April through July Brownlee reservoir inflows. Variations in this forecast from actual expenditures included in rates are collected the following year. Thus, the more accurate the forecast is, the smaller the amount that accrues in the deferral for inclusion with the following year's PCA "true-up" rate. All Parties agree that it is in everyone's best interest to have the most accurate forecast of PCA year expenses for the annual April 15th PCA filings. The Parties also agree that the

regression formula used in the past is no longer the best forecast tool. Comparing forecasts used by the Company in developing its Operation Plan to historical PCA filings shows that the Operation Plan forecast is a more accurate PCA year forecast than the regression formula. The Parties agree that the Company's forecast based upon its Operation Planning tools is the current best forecast and should be utilized for annual filings. The Parties agree that the Operation Plan forecast should be utilized for the Company's next annual PCA rate filing.

9. Third-Party Transmission Expense. The Parties agree that third-party transmission expenses are a necessary component to facilitate purchases and sales of energy and are reasonably considered a power supply expense. These third-party transmission expenses are reflected in two FERC accounts: Account 555, purchased power, and Account 565, transmission of electricity by others. Third-party transmission wheeling expenses necessary to facilitate purchases and sales of energy have been recorded in Account 565. Transmission expenses paid to third-parties for replacement of their transmission losses have been recorded in Account 555. Historically, neither of these items has been reflected in PCA computations. The Parties agree that deviations in these types of expenses from levels included in base rates should reasonably be reflected in PCA computations. In the future, the entire Account 555 will be tracked by the PCA as will Account 565. The Parties agree that third-party transmission expense including losses be included when the base is established as a result of the IPC-E-08-10 general rate case.

10. Power Supply Expense Distribution. Historically, power supply expenses were reported throughout the year using an AURORA based distribution. In order to

provide the financial community more transparent and understandable financial communications, the Parties agree that for purposes of PCA deferral reporting, the Base Net Power Supply Expenses will be distributed to monthly values based upon a monthly revenue shape. This adjustment will not affect the total PCA year calculation of the deviation between actual and Base Net Power Supply Expenses but will improve comparability between interim and annual financial reporting periods. A shadow PCA report that shows the PCA impacts associated with using an AURORA based distribution of power supply expenses will be provided to Commission Staff. The Parties agree that the new Power Supply Expense Distribution will be utilized when base rates are changed as a result of the IPC-E-08-10 general rate case.

11. Rate Spread/Revenue Allocation. PCA expenses are currently allocated to the various customer classes based almost 100% on energy. The Parties agree that this rate spread and revenue allocation needs to be reexamined following Idaho Power's current general rate case to determine if this methodology needs to be changed.

12. The Parties agree that this Stipulation represents a compromise of the positions of the Parties in this case. As provided in RP 272, other than any testimony filed in support of the approval of this Stipulation, and except to the extent necessary for a Party to explain before the Commission its own statements and positions with respect to the Stipulation, all statements made and positions taken in negotiations relating to this Stipulation shall be confidential and will not be admissible in evidence in this or any other proceeding.

13. The Parties submit this Stipulation to the Commission and recommend approval in its entirety pursuant to RP 274. Parties shall support this Stipulation before the Commission, and no Party shall appeal a Commission Order approving the Stipulation or an issue resolved by the Stipulation. If this Stipulation is challenged by any person not a party to the Stipulation, the Parties to this Stipulation reserve the right to file testimony, cross-examine witnesses and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

14. If the Commission rejects any part or all of this Stipulation, or imposes any additional material conditions on approval of this Stipulation, each Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding, within 14 days of the date of such action by the Commission, to withdraw from this Stipulation. In such case, no Party shall be bound or prejudiced by the terms of this Stipulation, and each Party shall be entitled to seek reconsideration of the Commission's order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate. In such case, the Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of the case. The Parties agree to cooperate in development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating in hearings and preparing briefs.

15. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just, and reasonable.

16. No Party shall be bound, benefited, or prejudiced by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory, or principle of regulation or cost recovery. No Party shall be deemed to have agreed that any method, theory, or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

17. The obligations of the Parties under this Stipulation are subject to the Commission's approval of this Stipulation in accordance with its terms and conditions and upon such approval being upheld on appeal, if any, by a court of competent jurisdiction.

18. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

DATED this 14th day of October 2008.

Idaho Power Company

By____________________
Donovan E. Walker
Attorney for Idaho Power Company

Idaho Public Utilities Commission Staff

By____________________
Weldon Stutzman
Attorney for IPUC Staff

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By ______________________________
Eric L. Olsen
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EXHIBIT A
LOAD GROWTH ADJUSTMENT RATE ("LGAR") CALCUATION
SETTLEMENT AGREEMENT

The Parties agree to use the following methodology to determine the Load Growth Adjustment Rate: The LGAR will consist of three components:

1. A return component based upon production-related rate base.
2. An expense component based upon production-related rate base.
3. A revenue component based upon production-related rate base.

Component 1: Production-Related Rate Base

The Production-Related Rate Base component would be the result of an IPUC order in general revenue requirement proceedings. As an example from the current Company request in Case No. IPC-E-08-10, page 1 of Exhibit No. 54 contains the demand and energy components of rate base allocated to the production function.

Demand	$428,477,746
Energy	$501,479,100
Total	$929,956,845

Assuming the Commission approved cost of capital structure is 50 percent debt and 50 percent equity and the approved overall rate of return is 8.55 percent:

Rate base	$929,956,845 @ 8.55% = $79,511,310
Debt	$464,978,423 @ 5.85% = $27,201,125
Equity	$464,978,423 @ 11.25% = $52,310,185

The Equity piece is grossed-up for taxes (1.642 multiplier)

Grossed-up Equity	$ 85,893,324
Debt	$ 27,201,125
LGAR Component 1	**$113,094,449**

Component 2: Production-Related Expenses

The Production-Related Expenses component would be the result of an IPUC order in general revenue requirement proceedings. An example from the current Company request in Case No. IPC-E-08-10, page 2 of Exhibit No. 54 contains the demand and energy components of expenses allocated to the production function.

Demand	$ 84,862,274
Energy	$372,833,595
Total	$457,695,869

The Parties recognize that included in this allocation are expenses related to customer service, and general and administrative expenses that are not directly associated with production and are reasonably removed. These amounts can be found in Exhibit 53 page 61, lines 467 through 485 and Exhibit 53 page 66, lines 489 through 520. The sum of these exclusions is $40,508,666.

Total from above	$457,695,869
Less exclusions	$ 40,508,666
LGAR Component 2	**$417,187,203**

Component 3: Production-Related Revenues

The Production-Related Revenues component would be the result of an IPUC order in general revenue requirement proceedings. An example from the current Company request in Case No. IPC-E-08-10, page 3 of Exhibit No. 54 contains the demand and energy components of revenues allocated to the production function.

Demand	$ 950,801
Energy	$106,270,965
LGAR Component 3	**$107,221,766**

LGAR Rate

The Load Growth Adjustment Rate (LGAR) is equal to the result of adding Components 1 and 2, subtracting Component 3, and finally dividing by the Commission approved Idaho jurisdictional firm load.

Component 1:	$113,094,449
Component 2:	$417,187,203
Component 3:	$107,221,766
(1) + (2) – (3)	$423,059,886
Idaho jurisdictional load	15,036,726 MWh (Exhibit 51)
LGAR Rate	**$28.14/ MWh**