BEFORE THE

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IDAHO PUBLIC UTILITIES COMMISSION

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IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION DBA AVISTA UTILITIES FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE IN IDAHO.	CASE NO. AVU-E-10-1/ AVU-G-10-1

DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT

IDAHO PUBLIC UTILITIES COMMISSION

AUGUST 5, 2010

Q. Please state your name and business address for the record.

A. My name is Randy Lobb and my business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed?

A. I am employed by the Idaho Public Utilities Commission as Utilities Division Administrator.

Q. What is your educational and professional background?

A. I received a Bachelor of Science Degree in Agricultural Engineering from the University of Idaho in 1980 and worked for the Idaho Department of Water Resources from June of 1980 to November of 1987. I received my Idaho license as a registered professional Civil Engineer in 1985 and began work at the Idaho Public Utilities Commission in December of 1987. My duties at the Commission currently include case management and oversight of all technical Staff assigned to Commission filings. I have conducted analysis of utility rate applications, rate design, proposed tariffs and customer petitions. I have testified in numerous proceedings before the Commission including cases dealing with rate structure, cost of service, power supply, line extensions, regulatory policy and facility acquisitions.

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

A. The purpose of my testimony is to describe the Stipulation (the Proposed Settlement) filed in this case and to explain the rationale for Staff's support.

Q. Please summarize your testimony.

A. Staff believes that the comprehensive Proposed Settlement resolving all issues in the general rate case and agreed to by all parties participating in the settlement process[1] is in the public interest, is just and reasonable and should be approved by the Commission.

Q. How is your testimony organized?

A. My testimony is subdivided under the following headings:

Stipulation Overview

Q. Please provide an overview of the Stipulation and Settlement.

A. The Stipulation filed with the Commission

[1] The Idaho Community Action Network and North Idaho Energy Logs, Inc., as intervenors, were provided notice of the settlement discussions, but did not participate.

provides for an annual overall increase in electric base revenue of $21.25 million or 9.25%. This increase is partially mitigated for the first two years by using $17 million in Deferred State Income Tax (DSIT) credits to offset a portion of the increase.

With the credit offset, the first year average net increase for electric service will be $8.25 million or 3.59% effective October 1, 2010. The second year increase will be an additional $9 million or 3.92% and the third year increase when all credits are exhausted will be an additional $4 million or 1.74%.

The Stipulation provides for an overall increase in natural gas revenue of $1.85 million or 2.62%. This increase is mitigated in the first year by using $500,000 in DSIT credits to offset a portion of the increase. With the credit, the first year revenue increase will be $1.35 million or 1.9% effective October 1, 2010. The remaining increase of 0.72% will occur in the second year when the credit expires.

The Stipulation and Settlement specifically identifies annual power supply cost levels for the Power Cost Adjustment (PCA) mechanism, supports a prudency finding for 2008 and 2009 Demand Side Management(DSM) expenditures, specifies rate spread to the individual classes and supports increased funding for low income DSM programs. The Stipulation also addresses accounting treatment for the Coeur d'Alene Tribe Settlement costs, Spokane River Relicensing costs, Colstrip lawsuit costs and Jackson Prairie Storage costs.

Finally, the Stipulation provides for workshops and discussion among the parties and the Company on a variety of issues including class cost of service, first block residential rate levels, and a variety of other consumer issues.

Although the Stipulation represents a comprehensive settlement of all revenue requirement issues in the case, it does not specifically identify revenue adjustments to the Company's case or specify an authorized return on equity (ROE).

Q. How does the annual revenue requirement increase for electric and gas service proposed in the Stipulation compare to the increase originally proposed by Avista?

A. Avista originally proposed to increase annual electric revenue by $32.114 million or 13.98% and increase annual natural gas revenue by $2.575 million or 3.6%. The Stipulated Settlement provides for an increase in annual electric revenue of $21.25 million or approximately 66% of the original request. That increase is further reduced by $13 million for one year and then by $4 million in the second year using the DSIT credits. Instead of paying an additional $32.114 million from October 1, 2010 to October 1, 2011, electric customers will only pay an additional $8.25 million or 26% of the original request. Through September 30, 2012, customers will pay a total of $25.5 million in additional electric costs or 40% of the $64.228 million that would have been required under the Company's original proposal.

The Stipulated Settlement provides for an increase in annual natural gas revenue of $1.85 million or 70% of the Company's original request. With the DSIT credit, the first year increase is $1.35 million or 52% of the Company's original request. The Stipulation and Settlement is attached as Staff Exhibit No. 101.

The Settlement Process

Q. Would you please describe the process leading to the Stipulated Settlement?

A. Yes. The Company contacted Staff the week of June 14, 2010 to discuss the possibility of scheduling a settlement workshop. Staff was scheduled to complete its company audit the same week and needed time to review its findings and develop its revenue requirement recommendations for hearing. Staff positions on cost of service, rate design and consumer issues were already well developed.

All parties were invited to attend or participate by phone in the settlement workshops on July 6 and July 8 in the Commission hearing room. Parties participating in both workshops included Commission Staff, Avista, Clearwater Paper Company, the Community Action Partnership Association of Idaho (CAPAI), the Idaho Conservation League and the Snake River Alliance. Idaho Forest Group only participated in the second workshop.

Settlement discussions were dominated by revenue requirement issues with additional discussions on other issues such as cost of service, rate design, low income weatherization funding and other customer service commitments. Revenue requirement discussion was framed by the electric and natural gas service increases proposed by the Company and the preliminary increase recommendation of Staff for electric service of approximately $16.4 million or 51% of the Company's proposal and for natural gas service of $792,000 or 31% of the Company's original proposal.

At the July 6, 2010 workshop the Company first proposed using $17.5 million in DSIT credits to mitigate the electric and gas service increases. Based on these revenue requirement positions and the positions of the parties on various other issues, negotiations ensued and the Stipulated Settlement was reached.

Q. How did the Commission Staff evaluate the

Stipulated Settlement to determine that it was reasonable?

A. In this case as in other past general rate cases, Staff evaluated the merits of the Stipulated Settlement by comparing it to the expected outcome if the case proceeded to hearing. In other words, Staff had to determine which process would result in the best deal for customers. In Staff's view, the best deal for customers is the lowest justifiable annual revenue requirement.

While the Commissioners make the ultimate decision on Company revenue requirement based on the record at hearing, it is the parties to the case that make revenue requirement adjustment recommendations on the record for the Commission to decide. The outcome at hearing in terms of revenue requirement must therefore be evaluated based on both the adjustments to the Company's revenue request that are presented on the record and how the Commission might decide each adjustment.

Revenue Increase and DSIT

Q. What type of adjustments to the Company's proposed revenue requirement had Staff identified and what was the dollar value of those adjustments?

A. As previously indicated, Staff's preliminary estimate of downward adjustments to the Company's proposed electric revenue increase of $32.114 million totaled approximately $15.7 million (a $16.4 million, 7.1%

increase) and approximately $1.78 million (a $792,000, 1.12% increase) on the natural gas service side. The big ticket issues identified by Staff for electric service included: an annual reduction in power supply costs of $6.8 million; a reduction in Return On Equity (ROE) to 10% for an annual revenue reduction of $4.3 million; elimination of all salary increases back to January 1, 2009 for a revenue reduction of $1.35 million, elimination of Lancaster transmission wheeling expense of $1.6 million; and elimination of working capital of $1.26 million. The remaining identified reduction of $550,000 in annual revenue consisted of 10 other individual adjustments.

On the natural gas side, Staff adjustments for ROE, salaries and removal of Jackson Prairie storage costs represented $1.5 million of the total identified revenue requirement reduction of $1.78 million.

Q. How confident was Staff that its adjustments could be justified on the record and accepted by the Commission upon hearing?

A. Staff took a very aggressive approach to developing its revenue requirement adjustments in preparation for testimony and in preparing for settlement negotiations. It is unlikely that all of the preliminary adjustments presented by Staff in negotiations would have survived ongoing review to be presented at hearing and it is unlikely that all of the adjustments presented at hearing would have been accepted by the Commission.

For example, Staff proposed eliminating 90% of the wheeling costs associated with the Lancaster power plant. These costs are actually incurred by Avista to wheel Lancaster power through Bonneville Power Administration's (BPA) system to Avista's service territory. While a reasonable argument could have been made to reduce the costs, it is questionable whether all of the recommended reduction would have been accepted.

In addition, Staff had to further develop justification to support the level of proposed reductions in salaries, ROE and working capital before it was presented in testimony. Company rebuttal at hearing could have presented arguments that some or all of the reductions were unjustified. On the gas service side, Staff would have had to offset the proposed revenue requirement reduction for removal of Jackson Prairie storage with benefits included in the Company's case that resulted from the addition of low cost natural gas storage.

Finally, Staff could not ignore the $17.5 million in DSIT benefits offered by the Company as part of the settlement. Given the complicated nature of the accrual and the difficulty in identifying the level of tax benefits already returned to customers, Staff was not confident that it could justify this level of credit to customers at hearing.

Q. How were the DSIT benefits derived and why are they now available to offset the present rate increase?

A. The deferred state income taxes are booked when there is a difference between the state income taxes paid and the amount reflected on the Company's books. When taxes and benefits are flowed through to customers, no DSIT is booked. When taxes and benefits are normalized, DSIT is booked.

Under normalization, the differential is then distributed to customers over the life of the assets. Federal and State tax laws usually dictate when normalization must occur. There are other accounting areas where the Company may elect to use either the flow-through method or the normalization method. This election once made is followed unless properly changed. The DSIT amounts discussed here are a result of Idaho taxes. No Federal or Washington State amounts are at issue.

Avista originally flowed these items through but changed to normalization when deregulation was being explored by many entities, both companies and commissions. Due to the timing of rate cases, not all DSIT reflecting the normalization methodology was included in rates. In the last general rate cases, Case Nos. AVU-E-09-1 and

AVU-G-09-1, the Company used the flow-through method for state income tax. With that change in accounting treatment, deferrals would not be booked. That left the DSIT balance of approximately $11 million on the books with a portion of those benefits belonging to customers. Avista offered the full amount of $17.5 million ($11 million grossed-up for taxes) as rate mitigation in the Settlement.

Q. Would all of the DSIT benefits used to mitigate the rate increase in settlement have been available to customers if this case had gone to hearing?

A. No. Staff believes that for a period of time DSIT was booked at a different level than was reflected in rates. In other words, customers actually received more tax benefits during the period than are reflected in the booked DSIT. Therefore, it could be demonstrated that the Company rather than customers is entitled to a larger portion of the $17.5 million DSIT.

Unfortunately, the mismatch in booked tax versus the ratemaking treatment over time makes it nearly impossible to accurately determine the exact allocation between customers and shareholders of the $11 Million ($17.5 million after tax gross-up) total DSIT booked during the period. It would require extensive study to track the actual amounts normalized in each case especially when there was a settlement or the amount is not shown in the rate case orders. Not only would it be time consuming and costly but the result could be subject to dispute. The Stipulated Settlement credits all of the DSIT to customers for maximum benefit.

Q. Did any other party to the case indicate intent to address the Company proposed revenue requirement in the rate case?

A. One party indicated that it might address appropriate ROE for the Company. Other than that, no parties planned to address revenue requirement issues.

Q. Why are a new return on equity and other specific revenue requirement adjustments not specified in the Stipulation?

A. Specific adjustments and ROE were not specified in the Stipulation to facilitate agreement on the overall revenue requirement. While the settlement parties generally agreed on a reasonable level of revenue, there was stark disagreement on the individual adjustments proposed to reach that revenue level. This was particularly true with respect to ROE. Rather than specify an ROE that all parties could not support, the Stipulation simply specified an overall revenue requirement that could be fully supported.

Q. Is the Company precluded from filing general rate cases over the next three years?

A. No. However, the issue of a rate case moratorium was discussed during negotiations. While Staff was concerned over the potential for multiple base rate increases in a single year and requested a moratorium as part of the Settlement package, it was not included in the final Stipulation. In exchange for the moratorium, the Company required an additional increase in revenue requirement that Staff and other parties were unable to support. The moratorium condition was therefore dropped in lieu of a lower overall revenue increase in this case.

Q. Could you please summarize why Staff supports the revenue requirement portion of the Stipulation?

A. Yes. Staff maintains that the combination of reduced base rate revenue requirement and the use of DSIT benefits to mitigate the increases as specified in the Stipulation is a better deal for customers than could have been achievable through hearings. Staff's best case scenario would have resulted in additional revenue of approximately $32.7 million over two years ($16.34 million each year), if all Staff adjustments proposed at settlement were accepted by the Commission. The Stipulated Settlement specifies additional electric revenue of $25.5 million over the two year period ($8.25 million in year one and 17.25 million in year two).

Given that neither Staff nor any other party had identified any DSIT benefits available to customers prior to settlement discussions, it is unclear how thoroughly this information could have been reviewed before prefiled direct testimony was due. Based on a preliminary review by Staff, it appears that over half of the $17.5 million DSIT might not have been normalized in rates so effectively may have already been flowed through to customers in past electric and natural gas rates. In any case, the amount of the DSIT available to customers would be subject to dispute at hearing. However, with the Stipulated Settlement customers receive the full $17.5 million of the DSIT benefit.

Class Cost of Service

Q. Please describe the Stipulated Settlement with respect to electric customer class cost of service and revenue spread among classes.

A. The Stipulation does not accept the Company's originally proposed class cost of service study but uses a less modified version of the cost of service study last approved by the Commission. The parties then agreed to move all classes one quarter of the way to "full" cost of service as proposed in the Company's original application.

Q. What was the cost of service modification and what was its impact?

A. The cost of service study originally submitted by the Company in this case showed that several customer classes were below cost of service including the residential class and several classes were above cost of service. The Company then proposed that all customer classes be moved one quarter of the way to "Full" cost of service. This means that once the overall revenue requirement increase is determined, those classes below cost of service would receive a larger portion of the increase and those above cost of service would receive a smaller portion of the increase.

The cost of service methodology initially proposed by the Company deviated from previously accepted cost of service methodology in three significant ways. It proposed a unique approach to the peak credit classification of production costs as energy or demand related; it classified all transmission costs as demand related instead of a split between demand and energy; and it used seven coincident peaks instead of all twelve monthly coincident peaks in formulating the major demand allocator. All of these proposed changes benefitted large, high load factor customers or customer groups.

The Company proposed the cost of service changes to benefit these customers because the Company observed that they were struggling in today's economy. Several large customers had down-sized and at least one had gone out of business. Staff observed that when costs are shifted away from large customers they are shifted to the other customer classes including the residential class, all of whom are also experiencing the downturn in the economy. In settlement, Staff accepted the classification that all transmission costs be demand related only because it is a more common cost of service practice.

The overall effect of settlement on cost of service is an increase in the cost responsibility of the residential class over what would have been allocated under previously approved cost of service methodology, but a lower allocation than that originally proposed by the Company.

All parties agreed that the one quarter move to full cost of service as originally proposed by the Company was reasonable. Staff recognizes that this relatively small move leaves some substantial room for movement in future cases.

Q. Did the parties agree to evaluate electric cost of service prior to the next Avista general rate case?

A. Yes. The parties agreed as part of the Stipulation to convene a public workshop to discuss the possibility of revising the peak credit method of classifying production costs. Possible revisions include the monthly production cost weightings (12cp vs. 7cp) and allocation of transmission costs.

Q. What did the parties agree to with respect to natural gas cost of service?

A. The parties agreed to accept the Company's proposed cost of service methodology and move all classes 60% toward full cost of service except for transportation service which will be moved fully to cost of service. Staff supported this position because the methodology was previously approved by the Commission and class increases required to achieve 60% of full cost of service were all within a reasonable range. Staff also supported a full decrease in transportation rates to provide a more accurate price signal reflecting cost of service for that class.

Rate Design

Q. The Stipulation provides for an increase in the monthly electric residential customer charge. Why does Staff support the increase?

A. The Company originally proposed to increase the monthly electric and natural gas customer charges from the current $4.60/month to $6.75/month and from $4.00/month to $6.75/ month, respectively. The Stipulation limits the increase in the electric customer charge to $0.40/month from the current $4.60/month to $5.00/month. No change in the monthly natural gas customer charge is proposed in the Stipulation.

Staff supported the limited customer charge increase as part of a negotiated settlement and to recognize the increased investment made by the Company to install more sophisticated automated meters.

Q. Are there any other rate design changes specified in the Stipulation?

A. No. The residential energy rate differential for electric energy consumption between the first and second block will not change from the differential that currently exists. This is consistent with the Company's original proposal and provides a reasonable spread between the first and second blocks in Staff's opinion. The Stipulation does include a provision to convene a public workshop prior to the Company's next general rate case to discuss the appropriate threshold between the size of the first tier and second tier energy blocks for residential electric service. Staff welcomes such a discussion.

Q. What are the new first year residential energy rates and what is the impact on customer bills?

A. The base residential energy rates will increase from $0.0695/kWh to $0.07775/kWh for the first 600 kWh per month and from $0.07867/kWh to $0.08691/kWh for energy use above 600 kWh per month. The differential between the first and second block rate is maintained at $0.0092/kWh. The first year base energy rates with the DSIT credit is

$0.0735/kWh for the first 600 kWh per month and $0.0818/kWh for energy use above 600 kWh per month. The residential rate impact of the proposed Stipulation and Settlement is shown on Staff Exhibit No. 102.

Natural gas rate changes for all customer classes are shown on page 7 of Attachment B to the Stipulation and Settlement.

DSM Prudency

Q. The Stipulation in this case includes an agreement that Avista's demand side management (DSM) expenses in 2008 and 2009 were prudently incurred for the benefit of its Idaho customers. What are the costs associated with DSM for those two years?

A. The testimony filed by Avista does not state Idaho-specific DSM costs, but the Company's 2008 and 2009 DSM annual reports contain this information. Table 14(EG) in the 2008 report indicates that $4,079,015 was spent for DSM funded by Idaho electricity customers and that $2,143,380 was spent for DSM funded by Idaho natural gas customers. Similarly, Tables 11 and 12 in the 2009 report show Idaho electricity-funded DSM costs of $5,335,909 and $2,468,528 of costs funded by Idaho natural gas customers.

Total DSM expenditures in Idaho for 2008 and 2009 were $9,414,924 funded by electricity customers and $4,611,908 funded by natural gas customers.

Q. How will the approximate $14 million spent by Avista for DSM programs affect electric and natural gas rates?

A. DSM costs will have no <u>direct</u> effect on tariffed energy rates because Avista's electricity and natural gas DSM programs are funded through energy efficiency tariff riders, Schedules 91 and 191, respectively. Indirectly, however, prudent and cost-effective DSM programs, by definition, reduce the total of all bills paid by Avista's customers. In short, while customers do pay for Avista's DSM programs through the energy efficiency tariff riders, a prudency finding for past expenses will not affect the base rates under consideration in this case.

Q. Why does Staff support a prudency finding for 2008/2009 DSM expenditures as part of the settlement in this case?

A. Staff believes that Avista's DSM efforts in 2008 and 2009 were generally reasonable and cost-effective and that sufficient progress is being made toward improving the processes and transparency of its program evaluations.

In last year's rate case (AVU-E-09-01 and AVU-G-09-01), the Staff recommended that Avista's request for a prudency finding of its January through November 2008 DSM costs be deferred "...until such time that the Company is able to provide more comprehensive evaluations of its DSM programs and efforts." After the conclusion of that case, the Staff convened a DSM evaluation workshop with Avista Utilities, Idaho Power Company and Rocky Mountain Power. The outcome of the workshop was a Memorandum of Understanding (MOU) signed in December 2009 by Staff and a representative of each of the three utilities. The MOU included evaluation and reporting prerequisites that will allow Staff to evaluate DSM prudency requests by the utilities. Because the MOU agreement was not reached until the end of 2009, it contained language indicating Staff would allow reasonable leniency for reporting DSM program evaluations through 2009. The MOU also contained specific language allowing Avista Utilities to re-file its 2008 DSM prudency request without Staff opposition.

Q. Please describe Avista's progress in its DSM evaluation and reporting since the MOU was signed.

A. As a result of the Commission deferring Avista's request for a DSM prudency finding in Case Nos. AVU-E-09-01 and AVU-G-09-01, the aforementioned MOU, and similar DSM evaluation questions being raised in a Washington Utilities and Transportation Commission docket, Avista formed a collaborative process to examine DSM evaluation and low-income program issues. As part of this effort, the Company has been diligently working on a comprehensive DSM Evaluation, Measurement and Verification (EM&V) Framework for review by collaborative members, including the IPUC Staff. The Company has contracted with nationally-respected DSM evaluation experts to improve its own understanding as well as the collaborative's understanding of evaluation best practices. The Company recently reorganized its DSM group to further separate DSM evaluation, policy and planning from DSM implementation. Finally, the Company's Energy Efficiency Annual Report filed on April 1, 2010, which shows 2009 DSM performance, is much more detailed than its former "Triple-E" reports. In short, although Avista's DSM evaluation and reporting are not yet at the level anticipated by the MOU, and Staff has suggested further refinements as part of its comments in Case No. AVU-G-10-02, the Company appears to be making reasonable progress toward addressing remaining insufficiencies. Thus Staff is exercising the "reasonable and necessary leeway" during transition years as contemplated by the MOU. The MOU is attached as Staff Exhibit No. 103.

Consumer Issues

Q. Could you please describe the basis of Staff's support for the Service Commitments described in Section 16 (c) of the Stipulation?

A. Yes. The Company has agreed to address several areas of concern to Staff. Perhaps most important with respect to rate impact, the Company has committed to review its policies and address in its next general rate case the appropriateness of charging for services it now provides without charge to customers or other parties, e.g., establishing new accounts or managing tenant/landlord accounts. The Company also will re-examine its existing non-recurring charges to determine whether those amounts cover a reasonable portion of the Company's current cost to provide those services. Staff believes it is prudent to re-examine the cost of providing non-recurring or on-going services, particularly where those services are discretionary and are clearly linked to a particular customer or third-party rather than customers in general. Appropriately pricing such services more closely aligns costs with benefits and reduces the upward pressure on rates.

The Company has agreed to use its best efforts to meet or exceed its current service level standard (the percentage of calls answered within a defined number of seconds) as established by the Company. Utilities must be accessible to customers, and an important measure of that accessibility is how promptly calls from customers are answered. Staff has expressed concerns in the past about both the Company's service level standard (80% of calls answered within 60 seconds) and the Company's performance in reaching the goals it has set for itself. Given Avista's target, which should be readily achievable, Staff believes it is necessary that the Company focus its attention on improving its performance in this area.

Avista has agreed to hold at least five energy conservation workshops for senior citizens in different Idaho communities prior to December 31, 2011. This program is targeted to seniors who might find themselves in tight financial situations that cause them to reduce their use of space heating in order to cut monthly bills. The primary goal of the workshops is to provide education on how to conserve energy without compromising comfort, health, and safety. This program has been offered in Washington, but not in Idaho. The Company previously indicated to Staff that it would implement the program in Idaho in 2009, but that did not occur.

The Company has agreed to begin tracking and reporting to the Commission monthly data regarding customer credit activity. Staff is in the process of developing a database to track residential customer arrearages, service disconnections, and reconnections. The data will enhance Staff's ability to more promptly identify and respond to credit-related issues and more fully inform the Commission on issues related to future policy development.

The Company has also agreed to actively manage the Low Income Weatherization and Low Income Energy Conservation Education Programs to assure that the stated goals and objectives of these programs are achieved and that costs associated with these programs are prudently incurred. Consistent with the terms of the DSM prudency MOU mentioned above, Staff believes these customer-funded programs need to be actively managed, not merely underwritten.

Q. Would you please explain Staff's support for additional funding for low income weatherization and low income DSM education?

A. Yes. Staff agreed to an increase in low income weatherization funding and additional funding for low income education programs in an effort to continue improvement in energy affordability. The increase in low income weatherization and education funding helps fill a growing need for programs that assist customers in reducing their monthly bills. They also save energy and help to reduce Company uncollectible billings to the benefit of all customers. With the Company's improved commitment to program oversight, Staff anticipates that the cost effectiveness of these programs will improve.

Q. Has the Company agreed to work with Staff to address some of the other concerns it has raised?

A. Yes. In coordination with Staff, Avista will develop and conduct a study on its deposit policy and practices with respect to residential customers. Among the objectives of the study would be to determine if current deposit policy correctly identifies customers who pose a credit risk to the Company, encourages customers who pose a credit risk to improve payment habits, and reduces the amount of credit and collection activity as well as bad debt associated with those customer accounts. An earlier deposit study independently conducted by Avista fell short of Staff's expectations and the hope is that a more collaborative approach will answer key questions about the efficacy of collecting deposits, particularly with respect to influencing individual customers' payment behavior.

The Company also will work with Commission Staff to address Staff's concerns about Avista's policies and practices with respect to: (a) opening and closing customer accounts and (b) offering term payment arrangements to customers. Staff has identified several issues that fall under these two topics that require further discussion in order to more fully resolve. Given its positive working relationship with Avista and the Company's commitment in this case, Staff expects to be able to reach resolution on these issues.

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

A. Yes, it does.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NOS. AVU-E-10-01 AVU-G-10-01 **STIPULATION AND SETTLEMENT**

This Stipulation is entered into by and among Avista Corporation, doing business as Avista Utilities ("Avista" or "Company"), the Staff of the Idaho Public Utilities Commission ("Staff"), Clearwater Paper Corporation ("Clearwater"), Idaho Forest Group, LLC ("Idaho Forest"), the Community Action Partnership Association of Idaho ("CAPAI"), the Snake River Alliance ("Snake River"), and the Idaho Conservation League ("Conservation League"). These entities are collectively referred to as the "Parties," and represent all parties in the above-referenced cases that

Exhibit No. 101
Case Nos. AVU-E-10-01/AVU-G-10-01
R. Lobb, Staff
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participated in settlement discussions.[1] The Parties understand this Stipulation is subject to approval by the Idaho Public Utilities Commission ("IPUC" or the "Commission").

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 all the issues raised in the proceeding and that this Stipulation and its acceptance by the Commission represent a reasonable resolution of the multiple issues identified in this Stipulation. 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. On March 23, 2010, Avista filed an Application with the Commission for authority to increase revenue from electric and natural gas service in Idaho by 14% and 3.6%, respectively. If approved, the Company's revenues for electric base retail rates would have increased by $32.1 million annually; Company revenues for natural gas service would have increased by $2.6 million annually. The Company requested an effective date of April 23, 2010 for its proposed electric/natural gas rate increase. By Order No. 31038, dated April 9, 2010, the Commission suspended the proposed schedules of rates and charges for electric and natural gas service for a period of thirty (30) days plus five (5) months, from April 23, 2010, until such time as the Commission enters an Order accepting, rejecting or modifying the Application in this matter.

3. Petitions to intervene in this proceeding were filed by Clearwater, Idaho Forest, CAPAI, the Idaho Conservation League, the Idaho Community Action Network ("ICAN"), Snake River, and North Idaho Energy Logs. By various orders, the Commission granted these interventions. *See*, IPUC Order Nos. 31041, 31052, 31054, 31058, 31068, 31069 and 31070.

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[1] The Idaho Community Action Network and North Idaho Energy Logs, Inc., as intervenors, were provided notice of the settlement discussions, but did not participate.

4. Public workshops for Avista customers were held on June 28, 2010, in Lewiston, Idaho, and on June 29, 2010, in Coeur d'Alene, Idaho, for the purpose of explaining the Company's Application, and in order to provide an opportunity for customers to ask questions of Staff. No customers attended the workshop in Lewiston, and approximately five customers attended in Coeur d'Alene. Settlement conferences were subsequently noticed and held in the Commission offices on July 6 and 8, 2010, and were attended by signatories to this Stipulation. Further public customer hearings have yet to be scheduled. The technical hearing was previously scheduled to begin on September 22, 2010. The Parties' request to modify the procedural schedule will be the subject of a separate Motion.

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

III. TERMS OF THE STIPULATION AND SETTLEMENT

6. Overview of Settlement and Revenue Requirement. The Parties engaged in productive settlement discussions in the conferences on July 6 and 8, 2010. The Parties agree that Avista should be allowed to implement revised tariff schedules designed to recover $21.25 million in additional annual electric revenue and $1.85 million in additional annual natural gas revenue, which represent a 9.25% and 2.62% increase in electric and natural gas annual base tariff revenues, respectively. However, these increases are offset by a rate impact mitigation plan discussed below resulting in a 3.59% increase in electric and a 1.9% increase in gas revenues. New electric and natural gas rates would become effective October 1, 2010.

The Parties agree that this settlement is not contingent upon any specific methodology for individual components of the revenue requirement determination, but all Parties support the overall increase to the Company's revenue requirement, and agree that the overall increase represents a fair, just and reasonable compromise of the issues in this proceeding and that this Stipulation is in the public interest.

7. Rate Impact Mitigation Plan. The electric rate impact to customers will be phased-in, beginning on October 1, 2010, over three years, resulting in a 3.59% increase October 1, 2010, a 3.92% increase on October 1, 2011, and a 1.74% increase on October 1, 2012, after giving effect to a two-year amortization of $17 million of Deferred State Income Tax (DSIT) refund which is being credited to electric ratepayers to mitigate the rate impact. The table below illustrates this rate mitigation plan in more detail.

ELECTRIC RATE IMPACT MITIGATION PLAN

Revenue Increase of $21.25 million or 9.25%, partially offset by the amortization of DSIT over 2 years.

	Year 1 (October 1, 2010)		Year 2 (October 1, 2011)		Year 3 (October 1, 2012)	
Total Increase	$21.25 million	9.25%	$21.25 million	9.25%	$21.25 million	9.25%
Less - DSIT Credit	$13.00 million	5.66%	$4.00 million	1.74%	$0.00 million	0.00%
Less - Prior Increase	$0.00 million	0.00%	$8.25 million	3.59%	$17.25 million	7.51%
Net Increase to Customers	**$8.25 million**	**3.59%**	**$9.00 million**	**3.92%**	**$4.00 million**	**1.74%**

The DSIT reflected on the Company's balance sheet totals approximately $11.1 million, and when adjusted for the effect of the revenue conversion factor of 0.63676, totals approximately $17.5 million, representing normalization of state income taxes for a period of years. As part of this mitigation plan, the Parties agree to credit $17 million of the DSIT to electric customers over two years to help offset the rate impact, and $0.5 million for one year to help offset a portion of the first year natural gas rate increase (thereby reducing the first year impact from 2.6% to 1.9%). The Company will record regulatory liabilities in Account 254 to account for the $17 million electric and $0.5 million gas DSIT refunds, and will record deferrals for the associated revenue related expenses and deferred federal income tax. The deferral amounts will be amortized as the refunds are passed on to customers. The Company will file, with its compliance filing, tariff schedules 099 (electric) and 199 (natural gas) which will be used to pass the DSIT credit back to customers.

8. Recovery of Lancaster Costs. In Case No. AVU-E-09-01, a settlement was reached in which the purchase of the output from the Lancaster combined-cycle generating plant was found to be reasonable with the recovery of the fixed and variable costs through the PCA. Those costs have now been incorporated into the base revenue requirement in this case.[2]

9. PCA Authorized Level of Expense. The new level of power supply expense, retail load and Clearwater Paper generation, and retail revenue credit rate resulting from the settlement revenue requirement for purposes of the monthly PCA mechanism calculations, are detailed in Attachment A.

10. Prudence of Energy Efficiency Expenditures. The Parties agree that Avista's expenditures for electric and natural gas energy efficiency programs from January 1, 2008 through November 30, 2008, and from December 1, 2008 through December 31, 2009 are prudent and recoverable.

11. Cost of Service. As part of this rate case, the Company prepared an analysis of using a peak credit method of classifying production costs, allocating 100% of transmission costs to demand, and allocating transmission costs to reflect any peak and off-peak seasonal cost differences over seven months, rather than assuming an equal weighting over twelve months. The Parties agree to take into account, for purposes of rate spread in this proceeding, the allocation of 100% of transmission costs to demand. The Parties have otherwise agreed to exchange information and convene a public workshop, prior to the Company's next general rate case, with respect to the

[2] The Lancaster power plant is a 275 MW gas-fired combined cycle combustion turbine located in Rathdrum, Idaho. Avista Utilities will purchase all of the output of the plant through 2026.

possible use of a revised peak credit method for classifying production costs, as well as consideration of the use of a 12 CP (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs.

The Parties have also agreed to move all electric rate schedules approximately 25% toward unity (except for the Street and Area Lighting Schedules, which will receive a percentage increase equal to the overall increase in revenue requirement). The following table shows the relative rates of return after giving effect to the foregoing adjustments.[3]

ELECTRIC PRESENT & PROPOSED RELATIVE RATES OF RETURN

	Present Relative ROR	Settlement Relative ROR
Residential Schedule 1	0.85	0.89
General Service Schedule 11	1.56	1.42
Large General Service Schedule 21	1.18	1.14
Ex Large General Service Schedule 25	0.61	0.70
Clearwater Paper Schedule 25P	0.85	0.88
Pumping Service Schedule 31	0.79	0.85
Street & Area Lighting Schedules	1.03	0.95
Overall	**1.00**	**1.00**

The Parties agreed to move all natural gas rate schedules approximately 60% toward unity (except for Transportation Service Schedule 146, which will receive a full decrease to unity), as shown below:

[3] The following assumptions were used to incorporate the settlement into the cost of service model for rate spread purposes: (1) Begin with the filed pro forma results of operation; (2) input the agreed-upon revised power supply adjustment; (3) reflect power supply changes in production property adjustment; (4) reflect cost of debt from AVU-E-09-01 in restated debt adjustment; (5) determine remaining adjustment necessary to achieve revenue requirement given rate of return from AVU-E-09-01; (6) run cost of service model on these results using the prior method, except transmission costs are 100% demand (allocated by 12 CP); (7) adjustment amount included as common cost allocated by four-factor allocator; (8) use results to determine rate spread with 25% movement toward unity.

NATURAL GAS PRESENT & PROPOSED RELATIVE RATES OF RETURN

	Present Relative ROR	Settlement Relative ROR
General Service Sch. 101	0.95	0.98
Large General Service Sch. 111	1.24	1.10
Interruptible Sales Service Sch. 131	1.10	1.03
Transportation Service Sch. 146	1.33	1.00
Overall	**1.00**	**1.00**

12. Rate Spread/Rate Design.

(a) As indicated above, the Parties agree that the increase in base revenue would be spread to move all electric rate schedules approximately 25% toward unity (except for the Street and Area Lighting Schedules, which will receive a percentage increase equal to the overall increase in revenue requirement) and all natural gas rate schedules approximately 60% toward unity (except for Transportation Service Schedule 146, which will receive a full decrease to unity).

(b) The Parties agree that there will be an increase in the basic charges, monthly minimum charges, and demand charges in Schedules 11, 21 and 25, as shown in Attachment B.

(c) Otherwise, a uniform percentage increase will be applied to each energy rate within each electric service schedule excluding Schedule 1, residential service where the block differential remains constant.

(d) The Parties agree that the current residential electric basic charge of $4.60 per month will be increased to $5.00, and the residential natural gas basic charge of $4.00 per month will remain the same.

(e) Attachment B provides a summary of the current and revised rates and charges (as per the settlement) for electric and natural gas service.

13. Resulting Percentage Increase by Schedule. The following tables reflect the agreed-upon percentage increase by schedule for electric and natural gas service, along with the first-year net rate impact resulting from the rate impact mitigation plan set forth in Section 7:

Electric Increase Percentage by Schedule:

Rate Schedule	General Increase	First Year Net with Credit
Residential Schedule 1	11.0%	4.3%
General Service Schedule 11	6.6%	2.6%
Large General Service Schedule 21	8.7%	3.4%
Ex Large General Service Schedule 25	9.8%	3.8%
Clearwater Paper Schedule 25P	7.2%	2.8%
Pumping Service Schedule 31	13.5%	5.2%
Street & Area Lighting Schedules	9.2%	3.6%
Overall	**9.3%**	**3.6%**

Natural Gas Increase Percentage by Schedule[4]:

Rate Schedule	General Increase	First Year Net with Credit
General Service Schedule 101	3.4%	2.6%
Large General Service Schedule 111	0.2%	-0.3%
Interruptible Sales Service Schedule 131	1.0%	0.6%
Transportation Service Schedule 146	-6.9%	-8.6%
Overall	**2.6%**	**1.9%**

14. Residential First Tier Energy Blocks. The Parties will exchange information and convene a public workshop, prior to the Company's next general rate filing, with respect to the appropriate size of the first tier energy block for Residential Electric Service Schedule 1 (currently at 600 Kwhs).

[4] As part of this case, the Parties agreed, for purposes of clarity and transparency, to move all natural gas commodity and demand costs from base rates to Schedule 150 (Purchased Gas Cost Adjustment); the retail rate schedules will now only reflect the non-commodity distribution rates. The application of the DSIT to natural gas customers would be spread based on each schedule's contribution to base revenues including the general increase in this case.

15. Effective Date for New Rates. The Parties agree, as an integral part of the Settlement, that the effective date for new electric and natural gas rates should be October 1, 2010.

16. Customer Service-Related Issues.

(a) Low-Income Weatherization Funding. The Parties agree that the annual level of funding of $465,000 to the Community Action Partnership (CAP) agencies for funding of weatherization (which includes administrative overhead) should be increased to $700,000. The continuation and level of such funding will be revisited in the Company's next general rate filing, or other appropriate proceeding. This total amount will be funded through the Energy Efficiency Tariff Rider (Schedules 91 and 191).

(b) Funding for Outreach for Low-Income Conservation. The Parties agree to annual funding of $40,000 to Idaho CAP for purposes of providing low-income outreach and education concerning conservation. This amount will be funded through the Energy Efficiency Tariff Rider (Schedules 91 and 191), and will be in addition to the $700,000 of Low-Income Weatherization Funding. The continuation and level of such funding will be revisited in the Company's next general rate filing or other appropriate proceedings.

(c) Other Service Commitments.

(i) The Company will review its policies and address in its next general rate case the appropriateness of charging for services it now provides without charge to customers or other parties, e.g., establishing new accounts or managing tenant/landlord accounts. The Company will also reexamine its existing non-recurring charges to determine whether those amounts cover a reasonable portion of the Company's current cost to provide those services.

(ii) The Company will use its best efforts to meet or exceed its current contact center service level standards.

(iii) In coordination with Staff, the Company will develop and conduct a study on Avista's deposit policy and practices with respect to residential customers. Among the objectives of the study would be to determine if the current deposit policy correctly identifies customers who pose a credit risk to the Company, whether it encourages customers who pose a credit risk to improve payment habits, and whether it reduces the amount of credit and collection activity as well as bad debt associated with those customer accounts.

(iv) The Company will hold at least five Senior Energy Conservation workshops in different Idaho communities prior to December 31, 2011.

(v) The Company will begin tracking and reporting to the Commission monthly data regarding customer credit activity.

(vi) The Company will actively monitor the Low Income Weatherization and Low Income Energy Conservation Education Programs to assure that the stated goals and objectives of these programs are achieved and that costs associated with these programs are prudently incurred.

(vii) The Company will work with Commission Staff to address Staff's concerns about Avista's policies and practices with respect to: (a) opening and closing customer accounts, and (b) offering term payment arrangements to customers.

17. Other Accounting Treatments. The Parties agree to the accounting treatment for the following items:

(a) **Coeur d'Alene Tribe Settlement and Spokane River Relicensing Deferrals** – The Parties agree to a ten-year amortization of the remaining balances beginning October 1, 2010 of the CDA Settlement Deferral, the Spokane River Deferral, and the Spokane River PM&E Deferral.

(b) **Colstrip Lawsuit Settlement** – The Parties agree to eliminate the amortization of the deferred costs, due to insurance proceeds received subsequent to the original filing of the case.

(c) **Jackson Prairie (JP) Storage** – The parties agree to the revised accounting treatment proposed by the Company for its existing cushion gas using the net book value of the utility assets at February 2010 to record the transfer of the cushion gas from non-recoverable (FERC Account No. 352.3), which is a depreciable asset, to recoverable (FERC Account No. 117.1), which is a non-depreciable asset. The JP assets that will transfer from Avista Energy on May 1, 2011, will include plant assets, operations and maintenance expenses, as well as cushion gas that will be recorded in both recoverable and non-recoverable FERC accounts using a similar allocation method.

IV. OTHER GENERAL PROVISIONS

18. 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.

19. 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 settlement terms 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.

20. 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 testimony and briefs.

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

22. 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.

23. 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.

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

DATED this 23rd day of July 2010.

Avista Corporation

By: ______________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

By: ______________________________
Donald L. Howell, II
Kristine A. Sasser
Deputy Attorneys General

Clearwater Paper Corporation

By: ______________________________
Peter Richardson
Attorney for Clearwater Paper

Idaho Forest Group

By: ______________________________
Dean J. Miller
Attorney for Idaho Forest Group LLC

Community Action Partnership Association

By: ______________________________
Brad M. Purdy
Attorney for CAPAI

Idaho Conservation League

By: ______________________________
Benjamin J. Otto

Snake River Alliance

By: ______________________________
Ken Miller

DATED this 23d day of July 2010.

Avista Corporation

By:________________________________
David J. Meyer
Attorney for Avista Corporation

Idaho Public Utilities Commission Staff

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Ken Miller

DATED this ____ day of July 2010.

Avista Corporation

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Ken Miller

Exhibit No. 101
Case Nos. AVU-E-10-01/AVU-G-10-01
R. Lobb, Staff
8/05/10 Page 17 of 31

DATED this 26th day of July 2010.

Avista Corporation

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Ken Miller

Exhibit No. 101
Case Nos. AVU-E-10-01/AVU-G-10-01
R. Lobb, Staff
8/05/10 Page 18 of 31

DATED this 23 day of July 2010.

Avista Corporation

By:____________________________

David J. Meyer
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Idaho Public Utilities Commission Staff

By:____________________________

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Dean J. Miller
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Snake River Alliance

By:____________________________

Ken Miller

Exhibit No. 101
Case Nos. AVU-E-10-01/AVU-G-10-01
R. Lobb, Staff
8/05/10 Page 19 of 31

DATED this ____ day of July 2010.

Avista Corporation

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David J. Meyer
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Idaho Public Utilities Commission Staff

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Benjamin J. Otto

Snake River Alliance

By: Ken Miller
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Exhibit No. 101
Case Nos. AVU-E-10-01/AVU-G-10-01
R. Lobb, Staff
8/05/10 Page 20 of 31

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UTILITIES COMMISSION

STIPULATION AND SETTLEMENT
Case Nos. AVU-E-10-01 & AVU-G-10-01

ATTACHMENT A

Electric PCA Authorized Expense and Retail Sales

Avista Corp
Idaho Pro forma October 2010 - September 2011
PCA Authorized Expense and Retail Sales

PCA Authorized Power Supply Expense

	Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10
Account 555 - Purchased Power	$92,384,879	$10,941,610	$9,233,475	$9,539,010	$7,063,545	$5,316,934	$5,361,214	$5,701,893	$7,193,928	$5,952,043	$7,390,676	$9,461,004	$9,229,546
Account 501 - Thermal Fuel	$30,868,464	$3,100,309	$2,835,019	$3,077,762	$1,679,320	$1,404,069	$1,311,997	$2,806,615	$3,112,239	$2,986,010	$2,882,561	$2,802,027	$2,870,538
Account 547 - Natrual Gas Fuel	$106,824,463	$10,726,297	$9,786,640	$8,238,144	$3,592,012	$2,793,269	$3,354,055	$10,431,836	$12,681,697	$12,137,828	$9,371,710	$11,156,828	$12,554,146
Account 447 - Sale for Resale	-$51,242,307	-$2,225,290	-$2,530,244	-$2,608,828	-$3,647,386	-$4,606,408	-$4,700,919	-$5,814,112	-$3,528,338	-$3,346,244	-$4,019,962	-$5,157,334	-$9,057,241
Power Supply Expense	$178,835,499	$22,542,926	$19,324,890	$18,246,087	$8,687,490	$4,907,864	$5,326,347	$13,126,233	$19,459,526	$17,729,637	$15,624,985	$18,262,525	$15,596,989
Transmission Expense	$17,646,416	$1,583,917	$1,428,385	$1,489,847	$1,545,721	$1,353,126	$1,434,184	$1,433,753	$1,488,811	$1,441,885	$1,464,318	$1,464,565	$1,517,909
Transmission Revenue	$12,388,460	$901,304	$825,004	$1,002,240	$898,431	$1,029,104	$1,371,347	$1,379,878	$1,150,203	$1,025,629	$1,041,304	$939,334	$824,682

PCA Authorized Idaho Retail Sales

	Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10
Retail Sales (w/o Clearwater), MWh	3,068,294	306,392	272,039	268,005	237,221	230,622	232,091	250,538	247,926	228,348	246,382	263,854	284,875
Clearwater Paper Generation	452,317	37,718	33,460	38,076	34,456	40,718	38,206	36,660	39,076	37,032	36,706	37,108	43,101
Retail Revenue Credit Rate	$48.00 /MWh												

Exhibit No. 101
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R. Lobb, Staff
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Attachment A

STIPULATION AND SETTLEMENT
Case Nos. AVU-E-10-01 & AVU-G-10-01

ATTACHMENT B

Electric and Natural Gas Rate Design

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-10-01
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2009
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Base Tariff Revenue Under Present Rates(1)	General Increase	Base Tariff Revenue Under Proposed Rates (1)	**Base Tariff Percent Increase**	Total Billed Revenue at Present Rates(2)	**Gen. Incr. as a % of Billed Revenue**	Total Gen Increase	Total Year 1 DSIT (Sch. 99) Offset	Total Billed Revenue at Proposed Rates (3)	**Percent Increase on Billed Revenue (4)**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential	1	$90,495	$9,980	$100,475	**11.0%**	$94,102	**10.6%**	$9,980	($6,107)	$97,975	**4.1%**
2	General Service	11,12	$29,245	$1,933	$31,178	**6.6%**	$31,301	**6.2%**	$1,933	($1,182)	$32,052	**2.4%**
3	Large General Service	21,22	$50,597	$4,398	$54,995	**8.7%**	$54,719	**8.0%**	$4,398	($2,690)	$56,427	**3.1%**
4	Extra Large General Service	25	$12,455	$1,216	$13,671	**9.8%**	$13,774	**8.8%**	$1,216	($743)	$14,247	**3.4%**
5	Clearwater	25P	$39,455	$2,847	$42,302	**7.2%**	$43,827	**6.5%**	$2,847	($1,743)	$44,931	**2.5%**
6	Pumping Service	31,32	$4,404	$594	$4,998	**13.5%**	$4,750	**12.5%**	$594	($363)	$4,981	**4.9%**
7	Street & Area Lights	41-49	$3,047	$282	$3,329	**9.2%**	$3,213	**8.8%**	$282	($172)	$3,323	**3.4%**
8	Total		$229,698	$21,250	$250,948	**9.3%**	$245,685	**8.6%**	$21,250	($13,000)	$253,936	**3.4%**

(1) Excludes all present rate adjustments (see below).

(2) Includes all present rate adjustments: Schedule 66-Temporary PCA Adj., Schedule 91-Energy Efficiency Rider Adj., and Schedule 59-Residential & Farm Energy Rate Adj.

(3) Includes all present and proposed rate adjustments: Schedule 66-Temporary PCA Adj., Schedule 91-Energy Efficiency Rider Adj., Schedule 59-Residential & Farm Energy Rate Adj., and Schedule 99-Deferred State Income Tax Adjustment.

(4) Includes one year effect of DSIT (Schedule 099) offset.

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-10-01
PRESENT & PROPOSED RATES OF RETURN BY RATE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2009

			Present Rates		Base	Proposed Rates	
Line No.	Type of Service (a)	Sch. Number (b)	Present Rate of Return (c)	**Present Relative ROR (d)**	Tariff Proposed Increase (e)	Proposed Rate of Return (f)	**Proposed Relative ROR (g)**
1	Residential	1	5.40%	**0.85**	11.0%	7.64%	**0.89**
2	General Service	11,12	9.86%	**1.56**	6.6%	12.14%	**1.42**
3	Large General Service	21,22	7.48%	**1.18**	8.7%	9.75%	**1.14**
4	Extra Large General Svc.	25	3.86%	**0.61**	9.8%	5.99%	**0.70**
5	Clearwater	25P	5.35%	**0.85**	7.2%	7.52%	**0.88**
6	Pumping Service	31,32	5.01%	**0.79**	13.5%	7.27%	**0.85**
7	Street & Area Lights	41-49	6.53%	**1.03**	9.2%	8.09%	**0.95**
8	Total		6.32%	**1.00**	9.3%	8.55%	**1.00**

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-10-01
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

(a)	Base Tariff Sch. Rate (b)	Present ERM & Other Adj.(1) (c)	Present Billing Rate (d)	General Rate Increase (e)	Proposed Billing Rate (f)	Proposed Base Tariff Rate (g)
Residential Service - Schedule 1						
Basic Charge	$4.60		$4.60	**$0.40**	**$5.00**	**$5.00**
Energy Charge:						
First 600 kWhs	$0.06950	$0.00313	$0.07263	**$0.00825**	**$0.07573**	**$0.07775**
All over 600 kWhs	$0.07867	$0.00313	$0.08180	**$0.00824**	**$0.08489**	**$0.08691**
General Services - Schedule 11						
Basic Charge	$6.50		$6.50	**$3.00**	**$9.50**	**$9.50**
Energy Charge:						
First 3,650 kWhs	$0.08715	$0.00647	$0.09362	**$0.00348**	**$0.09351**	**$0.09063**
All over 3,650 kWhs	$0.07433	$0.00647	$0.08080	**$0.00298**	**$0.08019**	**$0.07731**
Demand Charge:						
20 kW or less	no charge		no charge	**no charge**		**no charge**
Over 20 kW	$4.00/kW		$4.00/kW	$0.75/kW	$4.75/kW	$4.75/kW
Large General Service - Schedule 21						
Energy Charge:						
First 250,000 kWhs	$0.05765	$0.00576	$0.06341	**$0.00344**	**$0.06314**	**$0.06109**
All over 250,000 kWhs	$0.04919	$0.00576	$0.05495	**$0.00295**	**$0.05419**	**$0.05214**
Demand Charge:						
50 kW or less	$275.00		$275.00	**$50.00**	**$325.00**	**$325.00**
Over 50 kW	$3.50/kW		$3.50/kW	$0.75/kW	$4.25/kW	$4.25/kW
Primary Voltage Discount	$0.20/kW		$0.20/kW		$0.20/kW	$0.20/kW
Extra Large General Service - Schedule 25						
Energy Charge:						
First 500,000 kWhs	$0.04709	$0.00510	$0.05219	**$0.00356**	**$0.05324**	**$0.05065**
All over 500,000 kWhs	$0.03988	$0.00510	$0.04498	**$0.00302**	**$0.04549**	**$0.04290**
Demand Charge:						
3,000 kva or less	$10,000		$10,000	**$2,000**	**$12,000**	**$12,000**
Over 3,000 kva	$3.25/kva		$3.25/kva	$0.75/kva	$4.00/kva	$4.00/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW		$0.20/kW	$0.20/kW
Annual Minimum	Present:	$601,940			**$662,400**	
Clearwater - Schedule 25P						
Energy Charge:						
all kWhs	$0.03960	$0.00490	$0.04450	**$0.00206**	**$0.04463**	**$0.04166**
Demand Charge:						
3,000 kva or less	$10,000		$10,000	**$2,000**	**$12,000**	**$12,000**
Over 3,000 kva	$3.25/kva		$3.25/kva	$0.75/kva	$4.00/kva	$4.00/kva
Primary Volt. Discount	$0.20/kW		$0.20/kW		$0.20/kW	$0.20/kW
Annual Minimum	Present:	$555,600			**$602,260**	
Pumping Service - Schedule 31						
Basic Charge	$6.50		$6.50	**$1.00**	**$7.50**	**$7.50**
Energy Charge:						
First 165 kW/kWh	$0.07800	$0.00586	$0.08386	**$0.01052**	**$0.08891**	**$0.08852**
All additional kWhs	$0.06649	$0.00586	$0.07235	**$0.00897**	**$0.07585**	**$0.07546**

(1) Includes all present rate adjustments: Schedule 66-Temporary PCA Adj., Schedule 91-Energy Efficiency Rider Adj., and Schedule 59-Residential & Farm Energy Rate Adj. (Sch. 1 only).

AVISTA UTILITIES
IDAHO ELECTRIC, CASE NO. AVU-E-10-01
PROPOSED DSIT OFFSET BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2009

Line No.	Type of Service	Schedule Number	Proposed Revenue Increase	Percentage of Revenue Increase	DSIT Spread	Year 1 Forecasted kWh's Oct 10 - Sept 11	Schedule 99 Rates Per kWh	DSIT Spread	Year 2 Forecasted kWh's Oct 11 - Sept 12	Schedule 99 Rates Per kWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Residential	1	$ 9,981,877	46.97%	$ (6,106,560)	1,184,712,347	$ (0.00515)	$ (1,878,942)	1,199,181,404	$ (0.00157)
2	General Service	11,12	$ 1,931,958	9.09%	$ (1,181,904)	329,475,387	$ (0.00359)	$ (363,663)	344,565,318	$ (0.00106)
3	Large General Service	21,22	$ 4,397,489	20.69%	$ (2,690,229)	725,622,839	$ (0.00371)	$ (827,763)	759,119,941	$ (0.00109)
4	Extra Large General Service	25	$ 1,214,814	5.72%	$ (743,180)	295,499,806	$ (0.00251)	$ (228,671)	308,487,508	$ (0.00074)
5	Clearwater	25P	$ 2,848,277	13.40%	$ (1,742,475)	904,565,693	$ (0.00193)	$ (536,146)	912,239,479	$ (0.00059)
6	Pumping Service	31,32	$ 593,782	2.79%	$ (363,255)	66,409,211	$ (0.00547)	$ (111,771)	69,483,879	$ (0.00161)
7	Street & Area Lights	41-49	$ 281,803	1.33%	$ (172,397)	14,326,165	$ (0.01203)	$ (53,045)	14,585,393	$ (0.00364)
8	Total		$ 21,250,000	100%	$ (13,000,000)	3,520,611,447		$ (4,000,000)	3,607,662,923	

Exhibit No. 101
Case Nos. AVU-E-10-01/AVU-G-10-01
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AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-10-01
PROPOSED INCREASE BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2009
(000s of Dollars)

Line No.	Type of Service (a)	Schedule Number (b)	Base Tariff Revenue Under Present Rates Includes Sch. 150 (c)	Proposed General Increase (d)	Base Tariff Percent Increase (1) (e)	Base Tariff Revenue Under Present Rates Excludes Sch. 150 (2) (f)	Proposed General Increase (g)	Base Tariff Revenue Under Proposed Rates (h)	Base Tariff Percent Increase (2) (i)	Total Billed Revenue at Present Rates (j)	Total General Increase (k)	Percent Increase on Billed Revenue Before DSIT (l)	Total DSIT (Sch. 199) Offset (3) (m)	Total Billed Revenue at Proposed Rates (3) (n)	Percent Increase on Billed Revenue (3) (o)
1	General Service	101	$54,454	$1,850	3.4%	$22,205	$1,850	$24,055	8.3%	$48,783	$1,850	3.8%	($416)	$50,217	2.9%
2	Large General Service	111	$15,559	$24	0.2%	$4,426	$24	$4,450	0.6%	$13,523	$24	0.2%	($77)	$13,470	(0.4%)
3	Interruptible Service	131	$286	$3	1.0%	$70	$3	$73	4.2%	$246	$3	1.2%	($1)	$248	0.7%
4	Transportation Service	146	$395	($27)	(6.9%)	$395	($27)	$368	(6.9%)	$395	($27)	(6.9%)	($6)	$362	(8.3%)
5	Special Contracts	148	$93	$0	0.0%	$93	$0	$93	0.0%	$93	$0	0.0%	$0	$93	0.0%
6	Total		$70,787	$1,850	2.6%	$27,189	$1,850	$29,039	6.8%	$63,040	$1,850	2.9%	($500)	$64,390	2.1%

(1) The net increase of $1,350,000 (General Increase less DSIT) as a percentage of Base Rates (Including Sch. 150) results in an overall increase of 1.9%.

(2) Natural Gas Commodity Costs moved from base Sales Schedules to Schedule 150 as part of the stipulation.

(3) Includes one year effect of DSIT (Schedule 199) offset.

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-10-01
PRESENT & PROPOSED RATES OF RETURN BY RATE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2009

Line No.	Type of Service (a)	Sch. Number (b)	Present Rates: Present Rate of Return (c)	Present Rates: **Present Relative ROR (d)**	Base Tariff Proposed Increase (1) (e)	Proposed Rates: Proposed Rate of Return (f)	Proposed Rates: **Proposed Relative ROR (g)**
1	General Service	101	7.00%	**0.95**	8.3%	8.38%	**0.98**
2	Large General Service	111	9.20%	**1.24**	0.6%	9.40%	**1.10**
3	Interruptible Service	131	8.09%	**1.10**	4.2%	8.81%	**1.03**
4	Transportation Service	146	9.81%	**1.33**	(6.9%)	8.55%	**1.00**
5	Total		7.39%	**1.00**	6.8%	8.55%	**1.00**

(1) Natural Gas Commodity Costs moved from base Sales Schedules to Schedule 150 as part of the stipulation.

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-10-01
PRESENT AND PROPOSED RATE COMPONENTS BY SCHEDULE

(a)	Current Base Rate (b)	Gas Costs Moving to Schedule 150 (c)	New Base Rate (1) (d)	Present Rate Adj. (2) (e)	Present Billing Rate (f)	General Rate Increase (g)	DSIT (Sch. 199) Rate Decrease (3) (h)	Proposed Billing Rate (i)	Proposed Base Rate (j)
General Service - Schedule 101									
Basic Charge			$4.00		$4.00	**$0.00**		**$4.00**	**$4.00**
Usage Charge:									
All therms	$0.87815	($0.53674)	$0.34141	$0.48452	$0.82593	**$0.03374**	**($0.00729)**	**$0.85238**	**$0.37515**
Large General Service - Schedule 111									
Usage Charge:									
First 200 therms	$0.86316	($0.48520)	$0.37796	$0.01720	$0.39516		**($0.00361)**	**$0.39155**	**$0.39516**
200 - 1,000 therms	$0.79944	($0.53674)	$0.26270	$0.48039	$0.74309	**$0.00008**	**($0.00361)**	**$0.73956**	**$0.26278**
1,000 - 10,000 therms	$0.72485	($0.53674)	$0.18811	$0.48039	$0.66850	**$0.00006**	**($0.00361)**	**$0.66495**	**$0.18817**
All over 10,000 therms	$0.68401	($0.53674)	$0.14727	$0.48039	$0.62766	**($0.00826)**	**($0.00361)**	**$0.61579**	**$0.13901**
Minimum Charge:									
per month			$75.59		$75.59	**$3.44**		**$79.03**	**$79.03**
per therm	$0.00000		$0.00000	$0.48039	$0.48039		**($0.00361)**	**$0.47678**	**$0.00000**
Interruptible Service - Schedule 131									
Usage Charge:									
All Therms	$0.61264	($0.45293)	$0.15971	$0.40349	$0.56320	**$0.00676**	**($0.00286)**	**$0.56710**	**$0.16647**
Transportation Service - Schedule 146									
Basic Charge			$200.00		$200.00	**$0.00**		**$200.00**	**$200.00**
Usage Charge:									
All Therms	$0.11385		$0.11385		$0.11385	**($0.00826)**	**($0.00159)**	**$0.10400**	**$0.10559**

(1) The New Base Rate is derived from the Current Base Rate, less the Natural Gas Commodity Costs moved to Schedule 150, prior to the General Rate Increase.

(2) Includes Schedule 150 - Purchase Gas Cost Adj., Schedule 155 - Gas Rate Adj., Schedule 191 - Energy Efficiency Rider Adj.

(3) See Page 8 of Attachment A.

AVISTA UTILITIES
IDAHO GAS, CASE NO. AVU-G-10-01
PROPOSED DSIT OFFSET BY SERVICE SCHEDULE
12 MONTHS ENDED DECEMBER 31, 2009

Line No.	Type of Service (a)	Schedule Number (b)	Proposed Revenue Increase (c)	Total Proposed Revenue (d)	Percentage of Proposed Revenue (e)	DSIT (Sch. 199) Spread (f)	Forecasted Therms Oct 10 - Sept 11 (g)	Schedule 199 Rates Per Therm (h)
1	General Service	101	$1,850,164	$24,055,518	83.10%	($415,516)	56,964,500	$ (0.00729)
2	Large General Service	111	$24,328	$4,450,759	15.38%	($76,879)	21,296,718	$ (0.00361)
3	Interruptible Service	131	$2,956	$72,690	0.25%	($1,256)	438,617	$ (0.00286)
4	Transportation Service	146	($27,448)	$367,597	1.27%	($6,350)	3,983,377	$ (0.00159)
6	Total		$1,850,000	$28,946,565	100.00%	($500,000)	82,683,212	

Exhibit No. 101
Case Nos. AVU-E-10-01/AVU-G-10-01
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Attachment B

Residential Rate Impact of Proposed Settlement
Case No. AVU-E-10-01

	Current Base Rates	First Year Rates			Second Year Rates			Third Year Rates		
Basic Charge	4.60	5.00			5.00			5.00		
First 600 kWh	0.06950	0.07775			0.07775			0.07775		
Over 600 kWk	0.07867	0.08691			0.08691			0.08691		
DSIT Credit	0.00000	-0.00515			-0.00157			0.00000		
Monthly Usage	Monthly Bill	Monthly Bill	Increase Over Base Rates	Increase Over Previous Year	Monthly Bill	Increase Over Base Rates	Increase Over Previous Year	Monthly Bill	Increase Over Base Rates	Increase Over Previous Year
0	4.60	5.00	8.7%	8.7%	5.00	8.7%	0.0%	5.00	8.7%	0.0%
100	11.55	12.26	6.1%	6.1%	12.62	9.2%	2.9%	12.78	10.6%	1.2%
200	18.50	19.52	5.5%	5.5%	20.24	9.4%	3.7%	20.55	11.1%	1.6%
300	25.45	26.78	5.2%	5.2%	27.85	9.4%	4.0%	28.33	11.3%	1.7%
400	32.40	34.04	5.1%	5.1%	35.47	9.5%	4.2%	36.10	11.4%	1.8%
500	39.35	41.30	5.0%	5.0%	43.09	9.5%	4.3%	43.88	11.5%	1.8%
600	46.30	48.56	4.9%	4.9%	50.71	9.5%	4.4%	51.65	11.6%	1.9%
700	54.17	56.74	4.7%	4.7%	59.24	9.4%	4.4%	60.34	11.4%	1.9%
800	62.03	64.91	4.6%	4.6%	67.78	9.3%	4.4%	69.03	11.3%	1.9%
900	69.90	73.09	4.6%	4.6%	76.31	9.2%	4.4%	77.72	11.2%	1.9%
1000	77.77	81.26	4.5%	4.5%	84.84	9.1%	4.4%	86.41	11.1%	1.9%
1200	93.50	97.62	4.4%	4.4%	101.91	9.0%	4.4%	103.80	11.0%	1.8%
1400	109.24	113.97	4.3%	4.3%	118.98	8.9%	4.4%	121.18	10.9%	1.8%
1600	124.97	130.32	4.3%	4.3%	136.05	8.9%	4.4%	138.56	10.9%	1.8%
1800	140.70	146.67	4.2%	4.2%	153.12	8.8%	4.4%	155.94	10.8%	1.8%
2000	156.44	163.02	4.2%	4.2%	170.18	8.8%	4.4%	173.32	10.8%	1.8%
2500	195.77	203.90	4.2%	4.2%	212.85	8.7%	4.4%	216.78	10.7%	1.8%
3000	235.11	244.78	4.1%	4.1%	255.52	8.7%	4.4%	260.23	10.7%	1.8%
3500	274.44	285.66	4.1%	4.1%	298.19	8.7%	4.4%	303.69	10.7%	1.8%
4000	313.78	326.54	4.1%	4.1%	340.86	8.6%	4.4%	347.14	10.6%	1.8%
4500	353.11	367.42	4.1%	4.1%	383.53	8.6%	4.4%	390.60	10.6%	1.8%
5000	392.45	408.30	4.0%	4.0%	426.20	8.6%	4.4%	434.05	10.6%	1.8%
6000	471.12	490.06	4.0%	4.0%	511.54	8.6%	4.4%	520.96	10.6%	1.8%
7000	549.79	571.82	4.0%	4.0%	596.88	8.6%	4.4%	607.87	10.6%	1.8%
8000	628.46	653.58	4.0%	4.0%	682.22	8.6%	4.4%	694.78	10.6%	1.8%
9000	707.13	735.34	4.0%	4.0%	767.56	8.5%	4.4%	781.69	10.5%	1.8%
10000	785.80	817.10	4.0%	4.0%	852.90	8.5%	4.4%	868.60	10.5%	1.8%
Average Increase			4.1%	4.1%					11.0%	

Exhibit No. 102
Case Nos. AVU-E-10-01/AVU-G-10-01
R. Lobb, Staff
8/05/10

MEMORANDUM OF UNDERSTANDING
FOR PRUDENCY DETERMINATION OF DSM EXPENDITURES

This Memorandum of Understanding ("MOU") is entered into on this 21st day of December 2009 between Idaho Power Company ("Idaho Power"), Avista Utilities, PacifiCorp (d/b/a Rocky Mountain Power) (collectively "the Utilities" and individually as "the utility"), and the Staff of the Idaho Public Utilities Commission ("Staff"). All of the above-named entities are hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

A. The Parties agree that there exists a need for the Utilities and Staff to develop a common understanding of the basis upon which prudency of demand-side management ("DSM") expenditures can be determined for purposes of cost recovery.

B. The Parties attended a workshop on October 5, 2009, to discuss the contents of a more comprehensive utility annual DSM report that would demonstrate a commitment to, and accomplishment of, objective and transparent evaluation of DSM efforts. The agreed-upon principles ("guidelines") stemming from that workshop are set out below.

C. A copy of Staff's expectations for DSM prudency review is included as Attachment No. 1. Although Utilities will make a good faith effort to address Staff's expectations in following these guidelines, Staff expectations are informational and the Utilities will not be bound by them in the context of this Memorandum of Understanding.

D. The Parties recognize that implementation of the DSM prudency guidelines and evaluation framework described below will not automatically result in

DSM prudency findings. Instead, even with their implementation, future DSM prudency findings will require the preparation of a formal filing with the Commission.

NOW, THEREFORE, in consideration of the foregoing, the parties agree as follows:

Utility DSM Annual Report Requirements

1. Template. Idaho Power's *2008 Demand-Side Management Annual Report* will be used as a starting point template for enhanced reports beginning with reports for 2009 DSM operations and results. Elements like those found in Idaho Power's 2008 report will be included in each Utility's annual report for Idaho programs that reporting year, clearly identifying Idaho-specific data and narratives. The DSM annual reports may be filed as stand-alone documents or as a combination of documents (e.g., combined with a DSM business plan) that together fulfill the agreements in this MOU.

2. Table of Contents. Each annual DSM report will contain a table of contents that references all items specified below, including the appendix where the Cost-Effectiveness and Evaluation Table can be found.

3. Highlights or Introduction Section. Each annual DSM Report will include an initial overview of:

a. Process evaluations begun or completed during the previous year, modifications to DSM processes that resulted from those evaluations, and planned process evaluations and modifications for the coming year.

b. Impact evaluations begun or completed during the previous year, modifications to DSM programs that resulted from those evaluations, and planned impact evaluations for the coming year. This section will also highlight updates of assumptions or reference reports used in assessing cost-effectiveness during the past year and those expected to be reviewed in the coming year.

4. Cost-Effectiveness Section. Each DSM annual report will include a Cost-Effectiveness section and table listing individual programs/measures and the basis for estimates of their cost-effectiveness, i.e., formulas, data inputs and assumptions, and source/rationale for each datum and assumption, including the date of the source.

5. Evaluation Section. Each DSM annual report will include an Evaluation section and table showing the schedule for evaluations, including impact assessment, assumptions, source review, the schedule for field impact measurement, and completion date. If this schedule is not included, a reasonable explanation for why such a schedule, in whole or in part, is not necessary will be included.

a. It is anticipated that over a reasonable frequency cycle (e.g., 2 to 3 years), all substantial programs will have undergone process and impact evaluations. However, Staff agrees that the initial evaluation cycles may be longer for 2008 and 2009 programs until these guidelines are fully implemented.

b. A copy of each DSM evaluation completed since filing the previous DSM annual report will be included as an appendix to the annual DSM report, as well as any confidential cost information that are not included. The utility will supplement its DSM report with any confidential cost information once the Staff has signed a protective agreement with the utility.

6. Program Specific Section. Program-specific sections of the annual DSM Report will be reported by sector or by customer class, with a description of each

individual program offered in the sector or customer class, and will include a list of measures within each program.

a. Process Evaluation. Each program-specific section will have a process evaluation description that includes:

i. Program implementation modifications undertaken during the course of the year and the rationale behind the change(s).

ii. Other process issues identified during the course of the year.

iii. Any formal process evaluation undertaken during the year.

iv. Total process evaluation cost, inclusive of both utility-provided and contract-provided services, and names of primary outside evaluators conducting process evaluations and titles of internal evaluators. The DSM Report will indicate which cost information is considered confidential; each utility will supplement its DSM report with any program evaluations containing confidential proprietary information once the Staff has signed a protective agreement with the utility.

v. Process changes completed or planned during the upcoming year, if any.

b. Impact and Cost-effectiveness Evaluation. Each program-specific section will include an impact and cost-effectiveness evaluation description including:

i. Primary assumptions and source (with year source was produced) used in the initial determination of cost-effectiveness.

ii. Primary assumptions and source (with year source was produced) used to determine post implementation impact and cost-effectiveness.

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iii. Any changes from initial determination (or last evaluation) used for current cost-effectiveness evaluation and the reason for the change (such as updated assumptions, sources or field measurement).

iv. Planned cycle for reassessment of cost-effectiveness assumptions or measurement.

v. Total impact evaluation cost, inclusive of both utility-provided and contract-provided services, and names of primary outside evaluators and titles of inside evaluators. The DSM Report will indicate which cost information is considered confidential; each utility will supplement its DSM report with any program evaluations containing confidential proprietary information once the Staff has signed a protective agreement with the utility.

vi. Changes in program due to evaluation results.

c. Market Effects Evaluations. Each program-specific section will describe any market effects evaluations that have been planned or completed by or for the utility, including those planned or completed by the Northwest Energy Efficiency Alliance that are pertinent to any programs for which the utility is claiming electricity savings or other impacts.

7. Expenses Without Direct Energy Savings. As discussed in the October 5 workshop, the Utilities have expenses associated with DSM-related activities for which they do not claim energy savings. Expenses associated with non-quantifiable energy saving programs and initiatives, including but not limited to, infrastructure, education, outreach, and research, will be identified in the DSM annual reports and may be considered reasonable and necessary expenses for a broad based DSM portfolio.

Reasonable evaluations of such programs and efforts, commensurate with their costs, will be accomplished and reported. The Utilities will include these expenses in the calculations which determine a cost-effective DSM portfolio.

Prudency Determination

8. A utility may request a DSM prudency review at any time.

9. The Parties recognize that planning, implementing, and evaluating DSM programs are not a precise science; they require the application of judgment and experience. Utilities are encouraged to continually review these programs and make appropriate program improvements.

10. Within that context, review of utility demand-side management expenses for prudency shall take into consideration utility compliance with the planning, evaluation, and reporting guidelines listed above. A showing by the utility that it made a good faith effort to reasonably perform within these guidelines will constitute *prima facie* evidence that the utility's DSM expenses were prudently incurred for cost recovery purposes. By its performing within these guidelines, assuming there is no evidence of imprudent actions or expenses, the utility can reasonably expect that in the ordinary course of business Staff will support full cost recovery of its DSM program expenses.

Treatment of 2008 and 2009 Expenditures

11. Recognizing that their 2008 DSM reports have already been filed, the Utilities need not amend those reports, but instead will combine evaluation reporting for 2008 with 2009 in their 2009 reports to be filed in 2010. Because it is not possible to comply exactly with the requirements listed above for the historical expenses of 2008 and 2009, Parties agree to include as many components as possible in the 2010 Annual

DSM Report. Staff agrees to provide reasonable and necessary leeway for the implementation of the guidelines described in this MOU for the 2010 DSM reports.

12. Staff agrees that Avista Utilities may re-file its 2008 DSM prudency requests that were deferred in AVU-E-09-01 and AVU-G-09-01 as full-year prudency requests that will not be opposed by Staff.

Commission Not Bound by This Memorandum of Understanding

13. The parties to this Memorandum of Understanding acknowledge that the Commission Staff binds only itself and has no explicit or implicit authority to bind the Idaho Public Utilities Commission.

IN WITNESS WHEREOF, the Parties hereto have caused this Memorandum to be executed in their respective names on the dates set forth below.

Dated this 25 day of ~~December 2009.~~ January 2010

IDAHO PUBLIC UTILITIES COMMISSION STAFF

By: Randy Lobb

Randy Lobb
Representing the Idaho Public Utilities Commission Staff

Dated this 22nd day of December 2009.

IDAHO POWER COMPANY

By: J R Gale

Representing Idaho Power Company

Dated this 21st day of December 2009.

AVISTA UTILITIES

By:

David J. Meyer
Representing Avista Utilities

Dated this 22 day of December 2009.

ROCKY MOUNTAIN POWER

By: ______________________
Representing Rocky Mountain Power

ATTACHMENT NO. 1

Staff Expectations for Cost-Effectiveness Tests, Methods and Evaluations

1. Cost Effectiveness Measurements. As stated at the October 5, 2009, DSM evaluation workshop, Staff believes that prudent DSM management requires that cost-effectiveness be analyzed from a wide variety of perspectives, including the ratepayer impact perspective, and that all programs and individual measures should have the goal of cost-effectiveness from the total resource, utility, and participant perspectives. (See IPUC Order No. 22299 issued January 27, 1989, and Order No. 28894 issued November 21, 2001.) If a particular measure or program is pursued in spite of the expectation that it will not, itself, be cost-effective from each of those three perspectives, then the annual DSM report should explain why the measure or program was implemented or continued.

2. Net-to-Gross Adjustments. The net-to-gross issue was also discussed at the evaluation workshop. Some of the references that the utilities assert that they use, such as the *California Standard Practice Manual*, actually require that all tests be done on a net savings basis. Staff continues to assert that most programs and measures have a significant number of participants who would have installed the measure or changed their behavior in the absence of the utility program. Absent new evaluation research to provide a basis for the net-to-gross adjustments used by each utility, the utility has the burden of explaining the source of its net savings adjustments or lack thereof. Staff will continue to assess whether utility cost-effectiveness estimates sufficiently and prudently include net-to-gross adjustments.

3. Third-Party Evaluators. Independence of evaluators from program and portfolio management is another important issue that was discussed at the evaluation workshop. While it was generally agreed that not all evaluations need to be performed by third-party evaluators, Staff believes such evaluations tend to be perceived as being more objective and transparent, and thus more credible, than evaluations performed by utility staff, all other factors being equal. While Staff will review all evaluations and may

review any evaluation in depth, utilities should expect that their self-evaluations may be scrutinized more closely than third-party evaluations, as may the programs themselves.

4. Estimating Non-Energy Benefits. Non-energy benefits are important and prudent factors to assess in analyzing cost-effectiveness and determining incentive levels, but Staff cautions against creating confusion by subtracting the estimated value of non-energy benefits from program and measure costs when reporting DSM costs on a cents per kWh basis.

5. Contractor Costs. After DSM reports are filed in 2010, Staff may reconsider whether to require inclusion of specific contract amounts paid to contractors in subsequent DSM reports.

6. Suggested Resources. In addition to the several evaluation, measurement, and cost-effectiveness manuals that were discussed at the workshop, Staff suggests it may be useful for utilities to generally follow the guidelines in the National Action Plan for Energy Efficiency's *Model Energy Efficiency Program Impact Evaluation Guide*, released November 2007. Another of NAPEE's reports titled *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers* may also be useful.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **5TH** DAY OF AUGUST 2010, SERVED THE FOREGOING **DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT,** IN CASE NOS. AVU-E-10-01_AVU-G-10-01, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY