McDowell & Rackner PC

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October 3, 2008

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket UE _____

Enclosed for filing is Idaho Power Company's Application to Accelerate Depreciation of Existing Metering Equipment to be Replaced by Advanced Metering Infrastructure ("AMI") Installation; and to Implement Revised Depreciation Rates for the Company's Electric Plant-In-Service, along with the Direct Testimony and Exhibits of Gregory W. Said and Courtney Waites.

Very truly yours,

Wendy McIndoo

Wendy McIndoo

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE ________

In the Matter of Idaho Power Company's Application to Accelerate Depreciation of Existing Metering Equipment to be Replaced by Advanced Metering Infrastructure ("AMI") Installation; and to Implement Revised Depreciation Rates for the Company's Electric Plant-In-Service	**APPLICATION**

Idaho Power Company ("Idaho Power" or "Company"), in accordance with ORS 757.140, hereby respectfully makes Application to the Oregon Public Utility Commission ("OPUC" or "Commission") for an Order granting the Company authorization to accelerate the depreciation of the existing metering equipment to be replaced by the Company's installation of Advanced Metering Infrastructure ("AMI") meters and equipment; and authority to institute revised depreciation rates for the Company's Electric Plant-in-Service.

Idaho Power seeks authority to accelerate the depreciation of its existing metering equipment in anticipation of, and prior to, the deployment of AMI technology to its Oregon service territory in 2010. Additionally, Idaho Power seeks authority to institute revised depreciation rates for the Company's Electric Plant-in-Service, based upon updated net salvage percentages and service life estimates for all plant assets. The proposed accelerated depreciation results in a rate increase, while the proposed revised Plant-in-Service depreciation rates result in a rate decrease.

In support of this Application, Idaho Power has filed the testimony and exhibits of Gregory W. Said and Courtney Waites, as well as other supporting attachments, concurrently herewith represents as follows:

I. AMI BACKGROUND

1. Idaho Power has developed an AMI Implementation Plan proposing a three-year deployment, beginning January 2009 and continuing through the end of 2011, for an AMI system covering roughly 99 percent of the customers in its service territory. This Plan is the culmination of nearly ten years of investigation and experience with AMI technology, including a number of pilot programs, a Phase One deployment of AMI technology to a limited number of customers in Idaho, and several reports to the Idaho Public Utilities Commission ("IPUC").

2. In 2003, after review of the Company's initial report on the implementation of time-of-use pricing to residential customers, the IPUC directed Idaho Power to implement AMI over its entire system by the end of 2004. IPUC Case No. IPC-E-02-12, Order No. 29196 at 10. The 2004 implementation was subsequently delayed because of the financial, technical, and implementation problems encountered with meeting that timeframe. *Id.*, Order No. 29226 at 2-3. The IPUC then adopted a phased-in implementation along with a collaborative evaluation approach, while directing the Company to continue to work towards implementation of AMI technology "as soon as possible." *Id.*, Order No. 29362 at 12; IPUC Case No. IPC-E-06-01, Order No. 30102 at 5-6.

3. On December 30, 2005, the Phase One AMI Implementation Status Report was filed with the IPUC detailing the limited implementation as well as the time-variant pricing pilots and load control air conditioner cycling programs conducted with the AMI technology, and making recommendations for future evaluation and deployment. IPUC Case No. IPC-E-06-01. In that docket, the IPUC granted the Company an additional one-year period in which to work to resolve technical issues encountered in the pilot programs, allow for the technology to mature, and to assess further AMI deployment while ordering an updated status report to be filed by May 1, 2007.

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4. On May 1, 2007, the Company filed a detailed AMI Status Report, followed by an August 31, 2007, Implementation Plan describing and proposing a three-year deployment, beginning January 2009 and continuing through the end of 2011, of an AMI system covering roughly 99 percent of the customers in its service territory. IPUC Case No. IPC-E-06-01. The final Report and Implementation Plan is attached hereto as Attachment No. 1.

5. On August 4, 2008, Idaho Power filed an Application for a Certificate of Public Convenience and Necessity with the IPUC to Install AMI Technology Throughout Its Service Territory, consistent with the August 31, 2007, Implementation Plan. IPUC Case No. IPC-E-08-16. That Application is currently under review at the IPUC. This Application is attached hereto as Attachment No. 2.

II. AMI IMPLEMENTATION

6. Idaho Power proposes to install AMI throughout its entire service territory (99 percent of its customers)[1] in a systematic, three-year deployment schedule starting in January 2009 and continuing through the end of 2011. A map showing the proposed deployment is included as Attachment No. 3 to this Application. The schedule would start with the Company's Capital Region (Boise, Meridian, Eagle, Kuna, etc.) in 2009, move to the Canyon and Payette Regions (Nampa, Caldwell, Payette, Ontario, etc., including the Company's service territory in Malheur County and Baker County, Oregon) in 2010, and finish with the Southern and Eastern Regions (Twin Falls, Hailey, Jerome, Pocatello, Salmon, etc.). The actual meter exchanges will take place on a carefully planned schedule

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[1] There are approximately 4,000 customers system wide, including approximately 1500 customers in Oregon, who make up approximately 1 percent of Idaho Power's total customers whose electrical service comes from Idaho Power's 53 smallest distribution substations. The technology will work in these locations but the station infrastructure cost per customer is very high and is not offset by the benefits that would be achieved through AMI at this time. These customers are not currently included in the proposed deployment plan.

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that would generally follow meter reading routes, and progress route by route and substation by substation to install the required hardware throughout the system. The testimony of Mark C. Heintzelman, Idaho Power Delivery Services Leader in the Metering Department, filed in IPUC Case No. IPC-E-08-16, is attached hereto as Attachment No. 4 and provides a more detailed description of the AMI deployment, the technology being implemented, and some of the functionality and expected benefits from this AMI system, as well as a description of the contracts the Company has entered into with its AMI vendors.

7. The system-wide implementation of AMI technology is cost effective at this time. The August 31, 2007, AMI Implementation Plan filed with the IPUC in Case No. IPC-E-06-01, and attached hereto as Attachment No. 1, includes a summary of the Company's updated financial analysis concluding that the long-term benefits derived from reduced operating expenses are themselves sufficient to support a system-wide implementation. This has not always been the case. *See* IPUC Case No. IPC-E-02-12, Order No. 29362 at 11.

8. Additionally, the deployment of AMI technology has numerous other benefits for both the Company and its customers that cannot necessarily be quantified at this time, but exist. *See Id.*, Order No. 29196 at 10; *Id.*, Order No. 29362 at 12-14; IPUC Case No. IPC-E-06-01, Order No. 30102 at 5-6. The direct benefits that will increasingly be recognized following the start of the implementation are the operational savings associated with remote meter readings. Beyond the savings in meter reading costs are the benefits associated with time-of-use pricing, improved meter reading accuracy, outage management and monitoring, theft detection, employee safety, fewer estimated bills, less rebilling, flexible billing schedules, account aggregating, and more flexible rate designs.

9. The AMI technology selected for installation by the Company is a true two-way communications system that is fully capable of enabling the various other functionalities mentioned above, as well as other "smart-grid" operations into the future. Outage

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management functionality and hourly data collection will be implemented for each area in the year following deployment. The benefits of outage management integration will begin to be realized almost immediately, although achieving the full benefit from hourly data collection will likely require more time as additional back office systems and rate structures will need to be in place before significant benefits could be realized through time-of-use pricing and rates.

10. The Company has selected vendors and executed contracts to secure the required hardware, software, and labor for this deployment through its Strategic Sourcing Process which involves both a Request for Information ("RFI") and a Request for Proposals ("RFP") process. The Strategic Sourcing Process utilizes a cross-functional team made up of Idaho Power employees, with the assistance of a strategic sourcing consultant, and is led by the Company's Procurement Department professionals. The team conducted the RFI and RFP process to evaluate and assess the possible AMI solutions and ultimately to select vendors and successfully negotiate contracts for the deployment of the AMI technology. The team is made up of employees with expertise in procurement/purchasing, pricing/regulatory, meter support, finance, and other subject matter experts.

11. Because of the evolving and developing nature of the AMI technology, there is not a single-source vendor that can provide all of the necessary components required for an AMI deployment. Idaho Power has executed four contracts ("Agreements") with separate vendor companies that each provide a distinct product and/or service that is required to complete the supply chain necessary to install AMI. The contracted vendors (collectively, "AMI vendors") are: (1) <u>Aclara Power-Line Systems Inc.</u> ("Aclara"), formerly known as Distribution Control Systems Inc. ("DSCI"), to provide the Two-Way Automated Communication System ("TWACS®") which uses power line carrier communication technology, and primarily includes the AMI modules that are installed in the meters, software, and substation control equipment, as well as support service, project

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management, and training; (2) Landis+Gyr Inc. ("Landis+Gyr"), to provide the residential meters including the integration of TWACS® modules from Aclara into Landis+Gyr meters, providing electronic certified meter test results with each shipment, support services to manage the meter module integration and delivery, and meter/module failure analysis and resolution; (3) General Electric Company ("GE"), to provide the commercial meters, including integration of TWACS® modules into GE meters, providing electronic certified meter test results with each shipment, support services to manage the meter module integration and delivery, and meter/module failure analysis and resolution; and (4) Tru-Check, Inc. ("Tru-Check"), to provide meter exchange services (remove and replace) and plan the logistics to provide: material management, project management, exchange order management, meter exchange resource management, and other services necessary to exchange meters on schedule in years 2008 – 2011.

12. Idaho Power has negotiated firm unit pricing in its contracts to acquire and deploy AMI technology over the three-year plan. Based upon these Agreements, Idaho Power is able to make a reliable estimate of the total capital cost of the Project at $74.51 million. The portion of the capital cost estimate attributable to the Oregon jurisdiction is $3.64 million. This estimate does not include the accelerated depreciation of the existing metering equipment or the operation and maintenance benefits associated with the installation of the AMI technology. The Company is not seeking a rate increase associated with the capital investment at this time. This will be addressed in a future rate filing.

III. ACCELLERATED DEPRECIATION OF METERS

13. ORS § 737.355 requires the Company to accelerate the depreciation of the existing metering equipment that will be replaced by AMI meters prior to their removal from service in order to avoid having the previous investment in those meters stranded. Additionally, the accelerated depreciation of the old metering equipment, along with the

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corresponding rate recovery, is a fundamental assumption in the Company's financial analysis supporting the cost-effectiveness of the AMI deployment.

14. In order to depreciate the existing metering equipment prior to their removal from service, the Company requests that the net plant value of the meters be depreciated using a straight line method over an eighteen month period (January 2009 through June 2010). The Company estimates the net plant value of the existing Oregon metering equipment on December 31, 2008 (based on the actual net plant value as of March 31, 2008, and forecasted net plant values through December 31, 2008) to be $1,380,981. The eighteen month, straight line depreciation is $76,721 per month, as shown in Exhibit No. 1 to Ms. Waites' testimony. This results in a depreciation expense increase that the Company proposes be reflected in a rate increase to customers of $76,721 monthly, or $920,654 annually.

IV. REVISED ELECTRIC PLANT-IN-SERVICE DEPRECIATION RATES

15. As a matter separate from the AMI Implementation, Idaho Power has conducted a detailed depreciation study of all electric plant-in-service and updated the associated depreciation rates in its Idaho jurisdiction. This update results in depreciation expense reduction that the Company proposes be reflected in a rate decrease to customers. The Company, with this filing, seeks authority to implement these revised depreciation rates in its Oregon jurisdiction. The depreciation study was performed by the firm Gannett Fleming relative to electric plant-in-service at December 31, 2006, and updates net salvage percents and service life estimates for all plant assets. These depreciation rates are based on the straight line, remaining life method for production, transmission, and distribution plant and amortization of certain general plant accounts.

16. The Company's Application to the IPUC for revised depreciation rates, Case No. IPC-E-08-06, filed on April 1, 2008, is attached hereto as Attachment No. 5. Based on depreciable electric plant at December 31, 2006, of $3,467,925,739, the Idaho Application

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requests changes in depreciation rates that would result in a $6,713,451 decrease in total annual depreciation expense.

17. After filing its Application, the Company and the Staff of the IPUC (collectively referred to as the "Parties") conducted a series of settlement discussions. On August 27, 2008, the Parties agreed to several adjustments to the Company's originally proposed depreciation expenses for certain accounts associated with the Company's steam production plant, hydraulic production plant, diesel production plant, and transmission plant. Depreciation accruals originally proposed by the Company in its Application for its distribution plant, its general plant, and its other production plant categories to the case were also agreed upon by the Parties. The Company's Stipulation agreement reflects the changes agreed to by the Parties resulting in additional reductions in the requested depreciation expense from $6,713,451 to $8,514,422 and is attached hereto as Attachment No. 6.

18. The Company's Motion for Acceptance of Settlement filed with the IPUC on September 5, 2008, is attached hereto as Attachment No. 7. This Motion requests the IPUC to issue its Order accepting the Stipulation in settlement of all the remaining issues in the case.

19. After reviewing the record and the provisions of the Stipulation, the Commission accepted the Stipulation as a fair, just, and reasonable resolution of this case. IPUC Order No. 30639, attached hereto as Attachment No. 8. Depreciation rates approved in this Order shall become effective August 1, 2008, for the Company's Idaho jurisdiction.

20. The last changes to the Company's Oregon depreciation rates are set forth in OPUC Order No. 04-290, Case No. UM 1120, attached hereto as Attachment No. 9. These changes were based on the Company's electric plant-in-service at December 31, 2001. On November 18, 2003, the Company requested permission from the OPUC to revise its depreciation rates and have them become effective for accounting purposes on December

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1, 2003. In that case, the Oregon Commission recognized that the Idaho Commission had thoroughly reviewed and approved the Company's depreciation study and the resulting rates. The Oregon Staff reviewed the depreciation study and the supporting documentation. After evaluating and assessing the case, the Staff determined the rates approved in the Idaho Order were reasonable and should be adopted. On May 24, 2004, the Oregon Commission ordered the same stipulated depreciation rates that had been approved by the Idaho Commission in its Order No. 29363 dated October 22, 2003. Both the Idaho and Oregon revised depreciation rates became effective on December 1, 2003.

21. Similarly, in this filing, Idaho Power requests it be granted authority to institute revised depreciation rates for the Company's electric plant-in-service in exactly the same manner as that provided for in IPUC Order No. 30639. It is the opinion of the Company that this Order is reasonable and proper, in the public interest, and fair to ratepayers of the Company.

22. Approximately 5 percent of the Company's business in the state of Oregon and it would be administratively difficult and extremely cumbersome if it were required to charge different depreciation rates in Oregon than the rates ordered in Idaho, where it does the overwhelming majority of its business. The Company believes that the IPUC's Order is appropriate and respectfully requests the Oregon Commission adopt the provisions of IPUC Order No. 30639 and authorize Idaho Power to institute revised depreciation rates in accordance with that Order. This would result in the same depreciation rates being in effect for the Company on a system-wide basis.

23. The Company's depreciation expense allocation to Oregon is approximately 4.89 percent. Therefore, upon adoption of the proposed depreciation rates, the decrease to annual depreciation expense in Oregon would be approximately $416,355. The Company requests authority to implement the change in depreciation rates effective as of August 1,

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2008, with a change in customer rates effective January 2009, to coincide with the accelerated depreciation of meters as discussed above.

24. The revised depreciation rates authorized in IPUC Order No. 30639 will be incorporated in the Company's pending Idaho general rate case, IPC-E-08-10. If the IPUC's Final Order in that case revises any previously approved depreciation rate, the Company will make a second Oregon filing to reflect those revisions.

25. The combined impact of the proposed increase in customer rates from the accelerated depreciation and the proposed decrease in customer rates from the revised depreciation rates of electric plant-in-service results in a net annual increase to customer rates of $504,299 (accelerated depreciation, $920,654 – revised depreciation rates, $416,355 = net increase, $504,299). The Company proposes that this net amount be recovered from customers by use of a tariff rider that would be put in place for the eighteen month period of accelerated depreciation, January 2009 through June 2010. The proposed Tariff Schedule 92 is attached hereto as Attachment No. 10. Included as a Special Condition in the proposed Tariff is a provision by which the rider may be terminated should the system-wide deployment not take place.

V. REQUEST FOR EXPEDITIED CONSIDERATION

26. Because of the need to depreciate the existing metering equipment prior to their removal from service planned for October 2010, the Company seeks authority to start the accelerated depreciation as soon as possible. This will help minimize the rate impact to customers by accelerating the depreciation over a longer time period. Consequently, the Company is requesting that this Application be processed on an expedited basis.

27. In order to streamline the process and expedite the Commission's review of the Application, the direct testimony of Gregory W. Said and Courtney Waites is filed concurrently herewith. In addition, Idaho Power has assembled documents that it anticipates Staff and any potential intervenors will likely desire to examine as part of their

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analysis of this Application. The Company will work with Staff and any intervenors to expedite the discovery/review process.

VI. COMMUNCIATIONS AND SERVICE OF PLEADINGS

28. Idaho Power wishes to waive paper service in this docket. Communications and service of pleadings with reference to this Application should be sent to the following:

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Wendy McIndoo
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rgale@idahopower.com

VII. REQUEST FOR RELIEF

30 Idaho Power respectfully requests that the Commission issue an Order: (1) authorizing the accelerated depreciation of the existing metering equipment to be replaced by AMI over the period of January 2009 through June 2010; (2) authorizing the revised depreciation rates for electric plant-in-service effective as of August 1, 2008; and (3) authorizing a change in customer rates, effective as of January 1, 2009, to reflect both the

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accelerated depreciation and the revised electric plant-in-service depreciation rates, to be implemented by use of a rider.

DATED: October 3, 2008.

McDowell & Rackner PC

Lisa F. Rackner

IDAHO POWER COMPANY

Donovan E. Walker
Corporate Counsel
1221 West Idaho Street
P.O. Box 70
Boise, Idaho 83707

Of Attorneys for Idaho Power Company

ATTACHMENT NO. 1

May 1, 2007, AMI Status Report
and
August 31, 2007, AMI Implementation Plan

IDAHO POWER®
An IDACORP Company

MAGGIE BRILZ
Director, Pricing

May 1, 2007

IPC-E-06-01

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 West Washington Street
PO Box 83720
Boise, Idaho 83720-0074

Re: Phase One AMI Implementation Status Report

Dear Ms. Jewell:

Enclosed please find eight copies of Idaho Power's Phase One AMI Implementation Status Report. This report is filed in compliance with Idaho Public Utilities Commission Order No. 30102.

The Company previewed the information included in this report with Commission Staff on April 23. As stated in the report, the Company is committed to filing a supplement to this report no later than September 1, 2007 detailing the results of its in-depth financial analysis and the specifics on how it will proceed with AMI deployment.

If you have any questions regarding this report, please do not hesitate to contact me.

Sincerely

Maggie Brilz

Maggie Brilz

MB
cc: Ric Gale

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

2007 MAY -1 PM 4:50

IDAHO PUBLIC UTILITIES COMMISSION

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IPC-E-06-01

Advanced Metering Infrastructure (AMI) Status Report

Presented by Idaho Power Company
and the Idaho Public Utilities Commission

May 1, 2007

For clarity of understanding, the term AMR (Automated Meter Reading) has been upgraded to AMI (Advanced Meter Infrastructure), which better reflects the capabilities of the technology discussed in this report.

Table of Contents

Acronyms and Definitions

Due to the technical nature of this document, many abbreviations are used throughout to enhance readability. To avoid any confusion, use the table below as a guide to the acronyms and definitions of the terms used in this report.

Acronym	Description	Definition
AMR	Advanced Meter Reading	The components necessary to read a meter remotely using technology to retrieve meter-reading data through a one-way communication network.
AMI	Advanced Metering Infrastructure	Latest terminology for AMR to better reflect the expanded capabilities of two-way communication network. AMI systems measure, collect, and analyze energy usage information from advanced metering devices through various communication media. The infrastructure includes hardware, software, communications equipment, customer associated systems and data management software.
CIS	Customer Information System	Idaho Power's billing and customer system that contains all customer data utilized by Idaho Power employees to provide functionality for customer-related events such as billing, rates, service orders, and meter reading.
DCSI	Distribution Control Systems, Inc.	The vendor who sells the AMI power-line-carrier system Idaho Power implemented during the Phase One project.
EW	Energy Watch	The Critical Peak pricing program Idaho Power implemented in the Emmett area in 2005.
IEE	Itron Enterprise Edition®	The Itron product name of the Meter Data Management System Idaho Power purchased for the Phase One project.
IPC	Idaho Power Company	
IPUC	Idaho Public Utilities Commission	
MDMS	Meter Data Management System	A system that manages meter-reading data intended to validate the accuracy and completeness of the data and provide estimating routines to create billing-quality data. The system is also intended to compile the data to billing intervals for time-variant pricing programs.
MIRA	Multiple Input Receiver Assembly	Substation hardware that enables communication on multiple distribution feeders and phases at the same time, reducing the time it takes to locate and communicate with transponders.

Acronym	Description	Definition
MVRS	Manual Meter-Reading System	The software package and equipment Idaho Power purchased from Itron that facilitates the current manual meter reading process. This consists of the handheld devices that are used to collect the existing meter-reading data and the software to feed the information to the CIS.
NEXUS®	Nexus Energy Software	A hosted, Internet-based tool that Idaho Power contracted with Nexus Energy to provide customers with access to their hourly energy usage via the Idaho Power Web site.
TNS	TWACS® Network Server	This is the host software sold by DCSI that controls the signaling of information between the meter through power-line-carrier.
TOD	Time-of-Day	The Time-of-Use pricing program Idaho Power implemented in the Emmett area in 2005.
TWACS®	Two-Way Automatic Communication System	The DCSI AMI system Idaho Power installed during Phase One. The system uses power-line-carrier technology to communicate with the meter.
VEE	Validate, Estimate, Edit	A primary functional requirement of the MDMS system to validate meter data for accuracy and completeness and provide estimates for any missing interval data. This function also provides validation of any anomalies in the data and edits the data accordingly to achieve billing-quality data.
VSD	Variable Speed Drives	Customer equipment at the meter location that allows the customer to change the load of energy required to operate a piece of equipment.
XM	Extended Memory	A new meter transponder module developed by DCSI for TWACS® that has a rolling 7 days of hourly data stored in memory.

Part 1—Executive Summary

1. Purpose

Idaho Power Company (IPC) implemented a Phase One Advanced Metering Infrastructure (AMI)[1] System in 2004. A status report detailing the progress made and issues identified during Phase One, as well as IPC's two-year action plan for further evaluation and issue resolution, was filed with the Idaho Public Utilities Commission (IPUC) on December 30, 2005. As a result of its review of the Phase One status report, the IPUC issued Order No. 30102 directing IPC to file a report no later than May 1, 2007 specifically addressing the following issues:

A. Progress made on each issue identified in the Next Steps section of the December 2005 Status Report. The issues described in the Next Steps section centered around two main areas:

   1. Status of TWACS® System Issues;

   2. Status of MDMS Software Issues.

B. A more extensive analysis of potential benefits and costs.

C. An assessment of how IPC will proceed with AMI deployment, including an implementation time line.

2. Progress Summary

IPC has been very active improving upon the AMI system installed in Phase One. IPC has implemented numerous software upgrades and hot fixes in the past year and a half, the most significant of which was the Version 5 upgrade to the Meter Data Management System (MDMS) software. As a result of these efforts, all outstanding issues described in the previous report have been resolved, with the exception of the issue regarding meter compatibility with variable speed drives (VSD). IPC does not see this issue as a barrier to expanding AMI since relatively few VSD installations affect our metering equipment.

3. Updated Cost/Benefit Analysis

While IPC continues to consider other technologies, including a hybrid solution for AMI, at the present an AMI system utilizing TWACS® appears to meet the functional requirements for much of our service area. IPC is updating its in-depth financial analysis to incorporate revised pricing from various vendors for the system components needed to install AMI and to incorporate updated benefits examined during the past 15 months. In its December 2005 status report, IPC indicated its plan to conduct an in-depth financial analysis during the second half of 2007.

[1] The term AMI refers to systems that measure, collect, and analyze energy usage information from advanced metering devices through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications equipment, customer associated systems, and data management software.

Following the IPUC's order directing IPC to file a report not later than May 1, 2007, IPC accelerated this analysis time line. However, IPC has not been able to complete the analysis in time to include the results in this report. A comprehensive final analysis will be completed no later than September 1, 2007 and included in a supplemental filing to the IPUC.

4. Conclusions and Future AMI Implementation

Resolution of the technology issues discussed in the Phase One report is critical for success of AMI and was required before further implementation can occur. IPC has been very active improving upon the AMI system installed in Phase One. As a result of these efforts, all outstanding issues described in the December 2005 report have been resolved with the exception of the issue regarding meter compatibility with variable speed drives (VSD). IPC does not see this issue as a barrier to expanding AMI since relatively few VSD installation affect our metering equipment and the vendor has delivered a solution that IPC is currently testing.

IPC is in the process of updating its in-depth financial analysis. This analysis will include several deployment scenarios as well as revised product pricing and benefit valuation. IPC will submit to the Commission no later than September 1, 2007, a supplement to this report detailing its assessment of how it will proceed with AMI deployment.

Part 2—Status of AMI Phase One

1. Background & Procedural History

IPC implemented an AMI[1] System in 2004. A status report detailing the progress made and issues identified during Phase One as well as the Company's two-year action plan for further evaluation and issue resolution was filed with the IPUC on December 30, 2005. As a result of its review of the Phase One status report, the IPUC issued Order No. 30102 directing IPC to file a report no later than May 1, 2007 specifically addressing the following issues:

A. Progress made on each issue identified in the Next Steps section of the December 2005 Status Report. The issues described in the Next Steps section centered around two main areas:

1. Status of TWACS® System Issues:
   - Install necessary software upgrades;
   - Evaluate new substation equipment to increase bandwidth ability;
   - Evaluate new extended memory meter modules;
   - Resolve 480-volt meter reading issue;
   - Resolve issues concerning meter failures on variable speed drive customer equipment;
   - Evaluate primary metering with the AMI vendor;
   - Further evaluate tamper detection (energy theft detection) data;
   - Evaluate the outage management abilities of AMI to identify operational benefits;
   - Further investigate a solution for single-phase substations;
   - Investigate AMI performance while substation maintenance occurs.
2. Status of Meter Data Management System (MDMS) Software Issues:
   - Install Version 5.0 and conduct a functional test;
   - Resolve issues concerning MDMS' ability to process hourly data for the two time-variant pricing programs implemented in Phase One.

[1] The term AMI refers to systems that measure, collect, and analyze energy usage information from advanced metering devices through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications equipment, customer associated systems, and data management software.

B. A more extensive analysis of potential benefits and costs.

C. An assessment of how IPC will proceed with AMI deployment, including an implementation time line.

2. Scope of Phase One

AMI was installed in IPC's Emmett and McCall operating areas. AMI installation in the Emmett operating area included the communities of Emmett, Sweet, Montour, Horseshoe Bend, Banks, Crouch, Garden Valley, Lowman, and the surrounding rural areas of these communities. AMI installation in the McCall operating area included the communities of McCall, Lake Fork, Donnelly, Cascade, New Meadows, Riggins, and the surrounding rural areas of these communities.

AMI was installed for residential and small and large general service customers. During Phase One, 23,474 AMI meters were installed with 10,742 AMI meters installed in the Emmett operating area and 12,732 meters installed in the McCall operating area. This deployment represented 97% of the total meters in the Emmett and McCall service areas.

Since the completion of the Phase One implementation in 2004, an additional 2,500 AMI meters have been installed in the Emmett and McCall areas due to customer growth. Also, TWACS® equipment has been installed in one more substation bringing the total to nine.

The Phase One AMI project included the installation of the following systems:

- **TWACS® System**—This system, supplied by Distribution Control Systems Inc. (DCSI) is a Two-Way Automatic Communication System (TWACS®) consisting of software and physical equipment located in the field. This system utilizes power-line-carrier technology to communicate with meters and other TWACS® enabled equipment. This is the data collection system.

- **Itron Enterprise Edition (IEE)® Meter Data Management System (MDMS)**—This software system is the data management system for validating, editing, and estimating hourly consumption data retrieved by the TWACS® system and converting this interval data into billing quantities for time-variant pricing programs. In addition, the MDMS is the data source for other operational needs such as outage management, load research, customer usage information, etc.

- **Nexus Energy Software**—This Internet-based software system is the data presentment system through which customers can access their energy use data using the IPC Web site (www.idahopower.com).

Figure 1 illustrates how each of these three systems function within IPC's overall AMI system.

Idaho Power AMI System

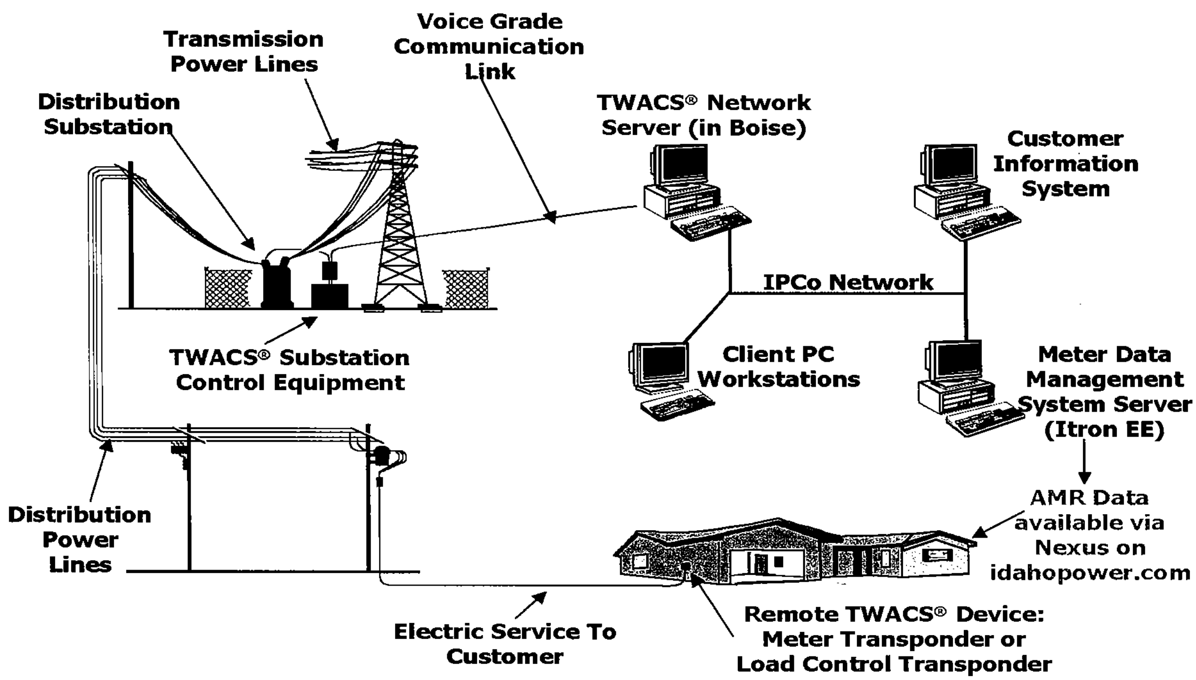

Figure 1 Idaho Power Company's AMI System

3. Status of Next Steps Identified in December 2005 Status Report

A. Specific Activities

During the past 15 months, IPC has investigated and evaluated the issues identified in the December 2005 Status Report. Following is the current status of each issue.

- **TWACS® Software Upgrade—**IPC has performed numerous TWACS® Network Server (TNS) software upgrades and hot fixes in the past year and a half. The current version in service is TNS 2.4. All known issues have been resolved and the software is performing as expected. IPC is investigating the next generation of TNS software in order to remain current with this evolving technology.

- **Bandwidth Capability—**Since the initial deployment of Phase One, DCSI developed and made available the Multiple Input Receiver Assembly (MIRA) for installation at the substation. IPC installed and evaluated MIRA. This enhancement improved the speed of data retrieval and reduced the frequency of missing hourly data.

- **Extended Memory (XM) Modules—**IPC purchased, installed, and tested meters with extended memory (XM) modules. The module has been successful in retrieving historic data. This new feature will enable time-variant rates.

- **480 Volt Meters—**All existing 480-volt meters in the Phase One deployment areas were retrofitted with new hardware that solved IPC's issues with those installations. No further problems have been reported on 480-volt meter installations since the retrofit.

- **Variable Speed Drive (VSD) Compatibility—**IPC is still working with DCSI to resolve the meter failure issues associated with VSD compatibility. IPC has installed the latest hardware revision and is currently testing it in the field. As a result of these efforts, all outstanding issues described in the previous report have been resolved, with the exception of the issue regarding meter compatibility with variable speed drives (VSD). IPC does not see this issue as a barrier to expanding AMI since relatively few VSD installations affect our metering equipment, and the vendor has delivered a solution that IPC is currently testing. IPC and DCSI are dedicated to resolving the issue associated with VSDs.

- **Primary Metering—**Since the initial deployment of Phase One, DCSI developed and made available a TWACS® solution for primary metered customers. IPC installed and evaluated the primary metering equipment. The solution is working well and IPC is satisfied this issued is resolved.

- **Tamper Detection—**IPC has evaluated the TWACS® tamper detection data over the past year and has determined that the value of tamper data could be enhanced with further development of additional analysis tools. IPC will research the availability and capability of tamper detection software.

- **Outage Assessment—**IPC has used DCSI's outage assessment software for the past two years for cycling air-conditioners and for the analysis of the TWACS® power outage management capabilities. IPC is confident that the outage assessment software can enhance IPC's outage management capabilities as AMI is expanded system-wide.

- **Single-Phase Substations—**After further evaluation of the single-phase substation solution, IPC has determined TWACS® is not cost effective for stations that serve a small number of customers. This is true for three-phase or single-phase substations. None of IPC's single-phase stations serve enough customers for TWACS® to be economically feasible. Therefore, IPC will analyze other technologies for use in these areas.

- **Temporary Substation Transformers—**IPC used mobile transformers and temporary TWACS® installations during the upgrade of the Cascade substation and during the replacement of the metal-clad switch gear at Emmett substation. In both cases the system and equipment performed adequately and no significant issues were encountered.

B. Status of the Meter Data Management System

The IEE® MDMS was not functional during Phase One, requiring manual intervention for bill processing associated with the two time-variant pricing programs offered in the Emmett area.

IPC has worked continuously with Itron since beginning deployment of Phase One. IPC stated in the December 2005 Status Report that a solution to the MDMS issue was expected to be implemented in April of 2006. IPC has tested and implemented numerous versions of this quickly developing software. The work has focused mainly around developing and testing the complex algorithms required to Validate, Estimate and Edit (VEE) hourly energy use data to support time-variant rates. After steadfast dedication by IPC and Itron employees, IEE® version 5, revision 11 was implemented in March of 2007. The software now has the specific functionality to support time-variant pricing, including critical-peakpricing. IPC is collecting hourly energy-use data on all 25,000 customers in the Phase One deployment area and supporting the Time-of-Day (TOD) and Energy Watch (EW) programs offered in the Emmett area by providing validated billing data to our billing system. IPC is working closely with Itron to insure the needs for functionality and scalability are addressed in future software releases.

IPC is currently developing daily work processes and the system functionality to support high-volume data validation and processing for billing.

C. Other Issues Further Investigated

While IPC continues to consider other technologies, including a hybrid solution for AMI, at the present an AMI system utilizing TWACS® appears to meet the functional requirements for much of our service area. IPC is updating its in-depth financial analysis to incorporate revised pricing from various vendors for the system components needed to install AMI. Variouse implementation scenarios will be evaluated as part of the financial analysis.

IPC has further investigated, identified, and quantified benefits available from AMI. Detailed results of this benefit investigation are included in Section 4.

4. AMI Benefits

A. General Discussion

Benefits of AMI can vary significantly from utility to utility based upon each utility's existing cost structure, geography, and customer base. IPC has investigated the benefits associated with AMI. Those benefits have been categorized as:

- Quantified (those for which a specific value has been determined);
- Unquantifiable (those for which a value is recognized, but for which an amount cannot be determined);
- Benefits not likely to provide significant value.

B. Quantified Benefits of AMI

Metering Operational Benefits

Meter reading operations change significantly through the introduction of AMI technology. IPC was able to identify the following benefits associated with full implementation of AMI:

- Reduction of the manual meter-reading workforce;
- Reduction of the Manual Meter-Reading System (MVRS) software-maintenance fees, hand-held data-collector maintenance fees, and repair costs;
- Elimination of erroneous meter readings are essentially eliminated reducing the number of re-read orders;
- Reduction of estimated meter readings due to access or weather issues are reduced;
- Elimination of the need to perform remote connect/disconnects in the field (this benefit requires additional devices and investment in order to be realized);
- Reduction of vehicle purchases, maintenance, and fuel costs associated with the manual meter reading process;
- Reduction of safety incidents and accidents that occur while performing metering functions in the field (reading, connect/disconnect and maintenance);
- Elimination of field visits for move-in/move-out orders that do not physically require a meter connect or disconnect;
- Enhanced ability to identify failed meters within 24 hours.

Customer Service Benefits

Based on Phase One, full implementation of AMI is estimated to result in a reduction in full-time employees at IPC's Customer Service Center. This benefit is derived from the following:

- Reduction in the cost associated with customer calls due to the reduction in erroneous bills, improved credibility with customers, fewer billing complaints filed with the IPUC, and the reduction in call length due to the availability of more energy use data.:

- Reduction in time spent in the Customer Service Center reviewing exception reports from manual meter reading, issuing orders, and completing billing adjustments due to erroneous readings and estimated readings.

Outage Restoration Benefits

Communication with the meter provides two types of information that are useful in outage situations. The first being, a communication response from the meter signifies there is an electrical connection to the customer and power is available at the customer's premises. Conversely, a lack of communication with the meter indicates that power may not be available.

a. Restoration Confirmation

Typically, crews respond to an outage situation and the problem is one isolated event. Frequently, however, there are multiple events that are not apparent to the Lineman. AMI equipment can be used to verify that all customers are back in service before the Lineman or Line Crew leaves the location, thereby eliminating a return trip and restoring power to the remaining customers sooner.

b. Avoided Dispatch

The AMI System can verify if the cause of the outage is due to a problem with IPC facilities. Customers who call with a power outage often are unaware of the cause of the problem. If the cause of the outage is actually the customer's equipment, the customer needs to hire an electrician to make repairs. If IPC receives a reply after pinging the meter, then IPC and the customer are assured that the electrical problem involves the customer equipment. IPC responded to 2,588 such calls in 2006.

Often during a power outage situation, Line Operation Technicians are called to assist the Lineman and/or Line Crew. AMI has the ability to "ping" the meters, and that provides information to determine the scope of the outage. IPC anticipates that with a more clear definition of the outage that there will be a reduction in the number of times it is necessary for the Line Operation Technicians to be involved with the outage.

c. Overloaded Equipment

At times transformers are overloaded from customer load. As a result, the fuse on the transformer melts and the circuit is broken, as designed. In these situations, a trouble call is dispatched, the fuse is replaced, and the transformer is potentially replaced as well. With AMI data, the amount of actual load on a transformer could be compared to the transformer size and the transformer could be replaced prior to the fuse melting. IPC's typical procedure is for the Lineman to replace the fuse and then the next day the crew would replace the transformer. With AMI overload data, the trouble call would be eliminated and a second outage for the customer avoided.

Distribution Engineering and Operations Benefits

AMI has the ability to provide voltage and the energy-load data for each distribution circuit, thereby allowing IPC to optimize the planning and operation of the distribution system. Also, AMI can work in concert with IPC's outage management system to improve the accuracy of customer outage data.

Irrigation Peak Rewards Program

Currently, our Irrigation Peak Rewards program utilizes electronic timer switches to turn-off irrigation pumps at specified intervals. Each year the customer chooses to change his participation the timers have to be manually reprogrammed in the field. With AMI technology at these locations, the timer could be remotely controlled and a field visit would not be necessary to customize the switches to satisfy the customer's needs.

C. Unquantifiable Benefits of AMI

Unquantifiable benefits are those AMI-related benefits that don't translate into manpower reductions or some other form of actual cost savings for IPC. The unquantifiable benefits include the following:

Customer Satisfaction

AMI deployment results in increased customer satisfaction in several areas:

- Customers will no longer need to provide IPC access to meters located on their property on a monthly basis. This access requires customers to control their pets and to locate fences and other objects so as not to conflict with IPC's access. In addition, having a stranger on one's property causes irritation for some customers.
- More accurate bills due to elimination of meter reading errors and estimated bills.
- Flexibility to participate in a time-variant pricing program if desired. Large-scale time-variant pricing programs will require additional investment in our Customer Information System (CIS).
- Energy-usage data made available to customers to help them make educated decisions regarding their energy usage.
- AMI's ability to communicate with the meter will help validate that all services have been restored following an outage, rather than waiting for the customer to call again.

Reduced Read-to-Pay Time

The manual read process allows for a three day period to collect the meter data and convert the data into a bill for the customer. With AMI, there is potential to reduce this time and therefore gain a one-time improvement in IPC's cash flow. IPC questions whether this one-time benefit will actually be realized. Those customers who pay their bill on a certain date every month may find that receiving their bill a couple days sooner probably won't effect when they pay.

Meter Operations—Theft Detection

The AMI technology offers features that assist in investigating potential instances of energy theft. These features are helpful, but are not expected to solely result in any significant cost savings. Some utility companies have identified as much as a 1% increase in revenues due to improved theft detection. However, during the Phase One AMI deployment very few instances of energy theft were discovered while performing approximately 24,000 meter exchanges and inspections. In addition, IPC is cautious about a potential increase in attempted theft when IPC employees are no longer visiting customer premises monthly.

High Bill/Energy Cost Inquiries

More accurate, timely data provided by AMI enables faster resolution of billing questions.

Additional Pricing Options

The more detailed usage information made available by AMI, whether it is hourly, daily, or grouped into time blocks, can provide customers with useful information to make informed decisions and more directly manage their energy consumption.The ability to capture individual customer usage data on an hourly basis allows for a adoption of alternative pricing structures to provide price signals to customers that encourage changes in usage patterns. Even small changes in consumption due to modifications in price signals could provide significant benefits. Implementing an AMI system that enables time-variant rates and other demand response programs can help meet future energy demands.

D. Potential Benefits Unlikely to Provide Significant Value

The following potential benefits were reviewed by IPC and after careful consideration at this time were deemed unlikely to provide a significant benefit:

- **Sale of used meters**—Replacement of meters during AMI implementation allows for the used meters to be sold to other electric utilities. The bulk of meter purchases today are solid-state electronic meters. With many utilities looking toward implementing some form of advanced metering, there is very little value in used mechanical meters.

- **Summary Billing**—Customers with multiple accounts and a summary bill could have the meters read and usage billed quicker with AMI. There are relatively few summary-bill customers, so this benefit has very little value.

- **Selectable bill date and bill frequency**—The ability of AMI to daily obtain customer usage potentially allows for customer choice of billing date and frequency. While this is a potential customer benefit this option possesses some risk of increased costs. IPC does need to maintain a somewhat uniform distribution of billing dates throughout the month in order to achieve system efficiency.

- **Meter reading for other utilities—**With specific enhancements, the AMI system has the capability to read other utility meters (gas, water, etc.). While this is a potential benefit, IPC has not had any discussions with other utilities or AMI vendors to quantify the likely increases in AMI licensing and maintenance costs.

- **Load research equipment—**AMI has the potential to provide hourly data for all customers. This could eliminate the need for customer load research meters that are used to sample and predict energy use characteristics. However, customer load research recently began collecting volt-amp reactive measurements for residential services. The typical residential AMI meter does not currently provide this data.

- **Optimized transformer and service wire sizing—**AMI can provide customer specific energy usage profiles and therefore the transformer and service wire can be optimized for delivering energy consumed by the customer with higher reliability. There is a cost balance to be considered between fewer standard sizes of transformers and service wires versus numerous custom-sized transformers and service wires. Customization also limits operational flexibility as system loads change over time.

- **End-of-Line Voltage—**Upon request, line voltage can be retrieved for a limited number of commercial meters, thus ensuring quality of service for the customer. This will benefit in determining when upgrades to the distribution system are necessary.

- **Power factor losses—**With additional investment, TWACS® can deliver power factor data on a limited number of commercial meters. This enables administering more equitable rates. This has very limited potential benefit since IPC already recovers its costs in the existing rates. This may be a shift between customers, but neutral to IPC.

- **Power quality monitoring—**With additional investment, TWACS® can deliver basic power quality data for a limited number of commercial meters. AMI can promote good power quality information, but actual power quality monitoring equipment is much more sophisticated and collects far more data than TWACS® can transmit.

- **Distribution Automation—**With additional investment, TWACS® has the ability to remotely control and communicate with distribution equipment such as reclosers, capacitors and generators. IPC has an existing radio-controlled capacitor system that will not be replaced by TWACS® until the end of the existing equipment's life.

- **Market segmentation and targeting—**AMI's ability to provide hourly usage data for all customers helps identify homogenous subgroups within traditional customer classifications that can be used for developing targeted programs.

E. AMI Benefits to Demand Side Management Programs

IPC's two demand response programs—A/C Cool Credit and Irrigation Peak Rewards—utilize switches to turn off customer load, thereby managing peak loads on IPC's system. Although TWACS® can provide the same service with the added benefit of two-way communication with each switch, it does not appear to be cost effective to replace the existing system with TWACS®.

IPC offered the TOD and EW Pilot Programs in the Emmett Valley again during the summer of 2006. A report detailing the results of the programs was filed with the IPUC on February 28, 2007. While EW, a critical peak, time-variant pricing program, provided a statistically significant change in customer usage patterns, the TOD program did not. IPC is currently evaluating the potential benefits available through the EW Program.

5. Conclusions and Future AMI Implementation

Resolution of the technology issues discussed in the Phase One report is critical for success of AMI and was required before further implementation can occur. IPC has been very active improving upon the AMI system installed in Phase One. As a result of these efforts, all outstanding issues described in the December 2005 report have been resolved with the exception of the issue regarding meter compatibility with variable speed drives (VSD). IPC does not see this issue as a barrier to expanding AMI since relatively few VSD installation affect our metering equipment and the vendor has delivered a solution that IPC is currently testing.

IPC is in the process of updating its in-depth financial analysis. This analysis will include several deployment scenarios as well as revised product pricing and benefit valuation. IPC will submit to the Commission no later than September 1, 2007, a supplement to this report detailing its assessment of how it will proceed with AMI deployment.

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IDAHO PUBLIC
UTILITIES COMMISSION

August 31, 2007

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 West Washington Street
PO Box 83720
Boise, Idaho 83720-0074

Re: Supplement to Phase I AMI Implementation Status Report
Case No. IPC-E-06-01

Dear Ms. Jewell:

Enclosed please find eight copies of Idaho Power's Advanced Metering Infrastructure (AMI) Implementation Plan. This report is a supplement to the Advanced Metering Infrastructure (AMI) Status Report filed on May 1, 2007, and is filed in compliance with Idaho Public Utilities Commission Order No. 30102.

If you have any questions regarding this report, please do not hesitate to contact me.

Sincerely

Maggie Brilz

Maggie Brilz
Director, Pricing

MB

c: Ric Gale
P&RS/Legal files

Pricing & Regulatory Services
Voice: 208-388-2848
Fax: 208-388-6449
mbrilz@idahopower.com

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1221 W. Idaho St.
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IDAHO POWER®
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IPC-E-06-01

Advanced Metering Infrastructure (AMI) Implementation Plan

Presented by Idaho Power Company
to the Idaho Public Utilities Commission

August 31, 2007

Table of Contents

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Implementation Plan

1. Introduction and Purpose

Idaho Power Company (IPC) has fully analyzed the costs and benefits of implementing AMI[1] throughout the remaining portions of its service territory. Based on this analysis, IPC proposes to install an AMI system covering roughly 99% of the customers in the service territory and proposes to do so by the end of 2011.

This report, supplemental to IPC's AMI Status Report filed on May 1, 2007, provides:

- A summary of the financial analysis
- An AMI implementation plan for the service territory
- A discussion for cost recovery
- Identification of the remaining issues

2. Financial Assumptions and Analysis Results

IPC's financial analysis compares the forecasted cost associated with the current meter reading operations to the forecasted costs associated with operations utilizing AMI. The analysis includes all components and costs associated with replacing existing metering equipment with advanced metering infrastructure capability. Included in these costs are metering and communication equipment, amortization of the undepreciated investment in the existing meters, reductions in Operations and Maintenance (O&M) expenses related to operational savings, AMI benefits, and costs of implementation.

A. 2007 Analysis Assumptions

The 2007 financial analysis is based on the following assumptions:

- The analysis covers a 30-year time frame.
- The meter count (i.e., number of customers) increases yearly by our current load forecast projections.
- The operation and maintenance costs and operational savings (including labor) escalate yearly based on Idaho Economics' CPI forecast.

[1] The term AMI refers to systems that measure, collect, and analyze energy usage information from advanced metering devices through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications equipment, customer associated systems, and data management software.

- Current productivity levels remain constant.
- Income Tax Rates are based on 2006 amounts.
- Property and Insurance Rates are based on 2006 amounts.
- The present value calculations are based on IPC's actual 2006 after-tax weighted average cost of capital.
- The book value of the existing meters is amortized over the three-year implementation schedule.
- The AMI meters have a 15-year life.
- Current meters have a 30-year life.
- All equipment is replaced at the end of its useful life.
- Replacement costs of meter equipment is at today's costs.

The results of the financial analysis indicate that the long-term benefits derived from reduced operating expenses are sufficient to support a decision to move forward with AMI implementation. Although the analysis indicates that implementation of AMI will increase IPC's revenue requirement in the early years, it is expected that the long-term benefits of reduced expenses plus additional benefits not yet identified or quantified will result in net benefits in the long term. For these reasons, IPC believes it is reasonable to proceed with AMI implementation.

3. Implementation Plan

Numerous factors were considered in developing the AMI implementation plan. The primary factors IPC considered were (in no particular order):

- Impact on revenue requirement
- Impact on existing employees
- Operational savings
- Impact on annual capital requirements
- Other major capital requirements needed to reliably serve existing customers
- Areas with high growth (new meters)
- Ease of implementation logistics

Based on a consideration of these factors, IPC has determined that a 3-year AMI implementation plan is reasonable. Work on the project would actually begin in 2008 with such tasks as pre-implementation planning, execution of contracts, ordering of long-lead materials, and installation of some communication equipment. Table 1 shows the year when AMI would be implemented in each regional area.

Table 1. AMI Implementation Time Schedule.

Year	Area of Implementation
2009	Capital Region (Boise, Meridian, Eagle, Kuna, etc.)
2010	Canyon Region and Payette Region (Nampa, Caldwell, Payette, Ontario, etc.)
2011	Southern Region and Eastern Region (Twin Falls, Hailey, Jerome, Pocatello, Salmon, etc.)

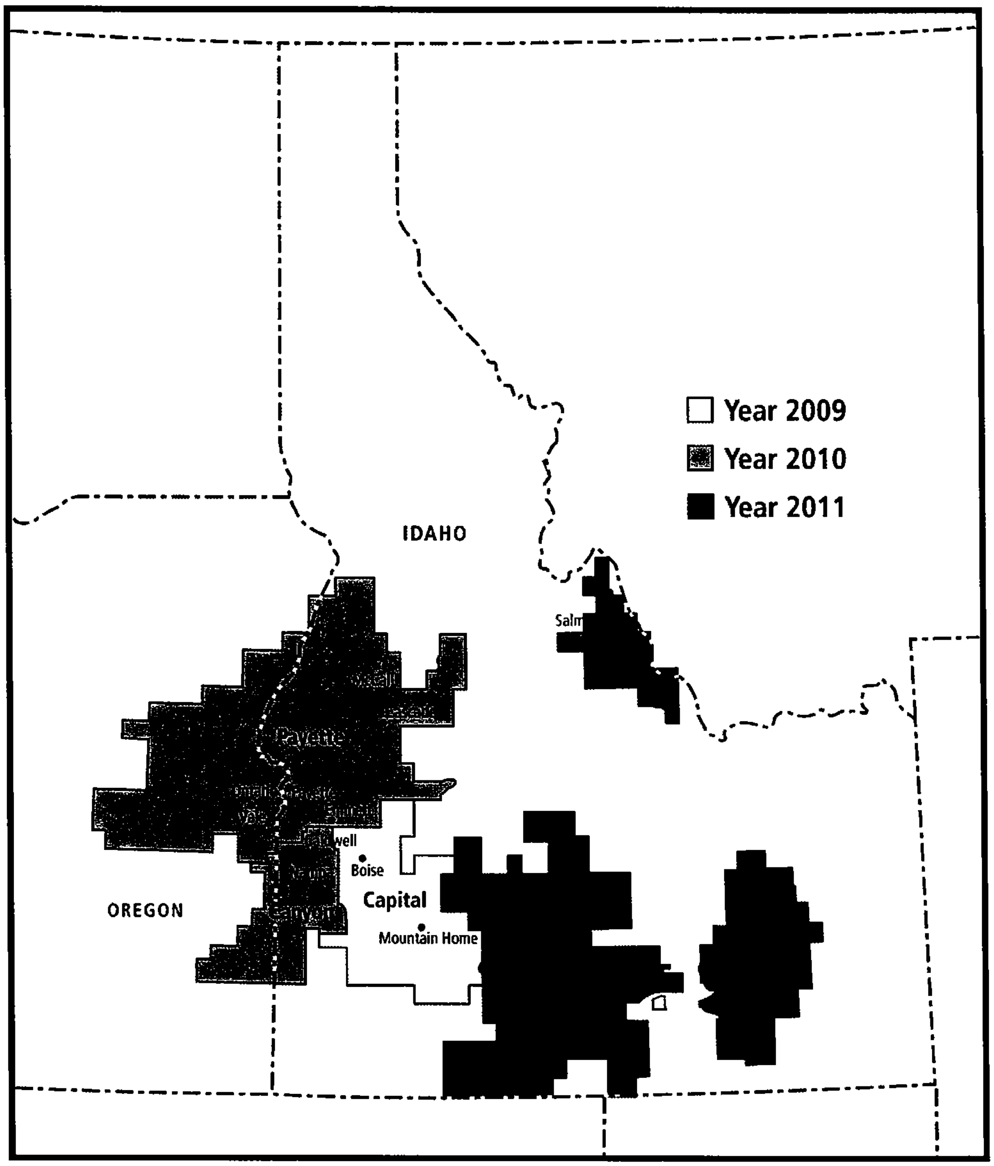

Figure 1. Idaho Power Company's Regional Implementation Map.

4. Cost Recovery

As referenced in IPC's May 1, 2007, AMI Status Report, implementation of AMI will provide customers increased benefits compared to the current operational practice of manually reading meters. In addition, AMI will create the foundation for the ability to offer customers pricing options and additional information about their energy consumption, which may lead to additional future benefits. For these reasons, IPC believes it is reasonable to pursue full implementation of AMI staged over a three-year period. However, the significant customer and economic growth IPC has been experiencing requires continued investments in infrastructure to connect and meet the energy needs of these customers. Additionally, there is an ongoing need to replace existing infrastructure to continue to reliably serve existing loads. Although AMI will provide benefits to customers, it is not an investment that is necessary in order for IPC to fulfill its obligation to meet new and existing service requirements. Therefore, in order to support the large capital expenditures needed to meet new and ongoing service obligations as well as to implement AMI, IPC has identified three regulatory needs between when AMI implementation begins and when AMI deployment is complete. These three regulatory needs are:

1. Three-year depreciation of the meters and metering equipment that AMI will replace.
2. Recovery of new metering equipment as it is placed in service and capture of O&M benefits as they begin to occur.
3. Establishment of appropriate depreciation rates for AMI equipment.

As part of its AMI implementation plan, IPC will bring before the Commission requests to address each of these regulatory needs.

A. Accelerated Depreciation of Existing Meters

An integral component of IPC's financial analysis is the assumption that IPC will begin collecting in rates the accelerated depreciation of the meters and metering equipment that AMI will replace at the time that AMI deployment commences on January 1, 2009. Specifically, IPC wishes to have the old metering equipment fully depreciated coincident with the completion of the three-year AMI deployment. This regulatory action is deemed essential to IPC's commitment to moving forward with AMI implementation.

B. Recovery of New Metering Equipment

The revenue requirement associated with the installation of AMI includes the return on and of the investment in metering equipment less the net O&M savings as they occur through the process changes enabled by the new technology. An adjustment to rates on January 1, 2009, to include the revenue requirement associated with AMI implementation will support IPC's financing requirements as it continues to fund significant investments in system infrastructure. This adjustment may take the form of specific inclusion in a general rate case test year or a separate rate mechanism specifically targeted to the AMI implementation.

C. Depreciation Rates for AMI Equipment

AMI meters and associated equipment have shorter useful lives than the standard metering equipment now being utilized by IPC. In order to appropriately recognize these shorter lives, IPC will include in its next depreciation filing before the Commission recommended depreciation rates for the various components of AMI equipment.

5. Issues to Resolve

A. CIS Assessment—Time-Variant Pricing

Implementation of AMI will provide the technology necessary to capture customers' energy usage on an hourly basis, creating the foundation for a variety of time-variant pricing options. Although IPC currently offers two time-variant pricing options to customers where AMI is installed, constraints within the Customer Information System (CIS), which require manual intervention in the rate change process, limit IPC's ability to offer time-variant pricing on a large-scale basis. Additional time and investment is required before IPC can offer time-variant pricing on a large-scale basis.

B. Meter Data Management System (MDMS)

The MDMS system currently has the functionality required to support the AMI system and time variant rates. As the AMI system expands beyond the current 25,000 endpoints, additional work related to scalability and usability will be required.

6. Conclusions

IPC has analyzed the costs and benefits of implementing AMI in the remaining portions of the service territory. Based on the results of the financial analysis, IPC believes implementation of AMI will provide customers with long-term benefits. In addition, AMI will create the foundation for the ability to offer customers pricing options and additional information about their energy consumption, which may lead to additional future benefits. For these reasons, IPC believes it is reasonable to pursue full implementation of AMI staged over a three-year period.

To recover the costs of implementation, it is essential that IPC 1) begin to collect accelerated depreciation of the meters and metering equipment that AMI will replace, 2) recover the costs of new metering equipment as it is deployed and capture O&M benefits as they begin to occur through the process changes enabled and necessitated by AMI, and 3) establish the appropriate depreciation rates for AMI equipment.

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ATTACHMENT NO. 2

Application for a Certificate of Public Convenience and Necessity to Install AMI (IPUC Case No. IPC-E-08-16)

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Attorney II

August 4, 2008

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-08-16
Advanced Metering Infrastructure ("AMI") Technology

Dear Ms. Jewell:

Enclosed please find for filing an original and seven (7) copies of Idaho Power's Application in the above matter.

In addition, enclosed are an original and eight (8) copies each of the testimonies of John R. Gale, Courtney Waites, and Mark Heintzelman that are being submitted in support of Idaho Power's enclosed filing. One copy of each of the testimonies has been designated as the "Reporter's Copy." In addition, a disk containing Word versions of each of the above testimonies has been provided for the Reporter and has been marked accordingly.

Also, delivered with this filing for the Commission's Review and records is a full-sized map showing Idaho Power's proposed deployment of AMI. Please note that only one full-sized map is being provided to the Commission.

Also enclosed are two (2) copies of a Protective Agreement, which I have executed. Please have one of the Staff attorneys execute both copies of the Protective Agreement. Please return one of the fully executed copies of the Protective Agreement to me at Idaho Power and retain the other original for the Commission's files.

Finally, I would appreciate it if you would return a stamped copy of this letter for Idaho Power's file in the enclosed stamped, self-addressed envelope.

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

If you have any questions about the enclosed documents, please do not hesitate to contact me.

Very truly yours,

Donovan E. Walker
Attorney II for Idaho Power Company

DEW:csb
Enclosures

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IDAHO PUBLIC
UTILITIES COMMISSION

Attorneys for Idaho Power Company

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO INSTALL ADVANCED METERING INFRASTRUCTURE ("AMI") TECHNOLOGY THROUGHOUT ITS SERVICE TERRITORY	CASE NO. IPC-E-08-16 APPLICATION

Idaho Power Company ("Idaho Power" or "Company"), in accordance with *Idaho Code* §§ 61-526, 61-502A, 61-525, 61-503, RP 052, and RP 112, hereby respectfully makes Application to the Idaho Public Utilities Commission ("IPUC" or "Commission") for an Order granting the Company a Certificate of Public Convenience and Necessity ("CPCN") to install Advanced Metering Infrastructure ("AMI") technology throughout its service territory, granting authorization to accelerate the depreciation of the existing metering infrastructure, and including the corresponding operation and maintenance benefits as they occur.

Idaho Power seeks approval of its three-year deployment of AMI technology to replace all meters in its service territory (99 percent of its customers)[1], along with the associated software, substation, and communications equipment. Idaho Power requests in this proceeding that the Commission issue its Order stating that, in the ordinary course of events, Idaho Power can (1) expect to ratebase the prudent capital costs of deploying AMI as it is placed in service, (2) accelerate the depreciation of the existing metering infrastructure replaced by AMI over the three-year deployment, and (3) include the operation and maintenance benefits in the accounting methodology.

In support of this Application, Idaho Power has filed the testimony and exhibits of John R. Gale, Courtney Waites, and Mark Heintzelman concurrently herewith and hereby represents as follows:

BACKGROUND

1. As a result of the very large purchased power costs and accompanying Power Cost Adjustment rate increases stemming from the 2000-2001 energy crisis, the Commission ordered Idaho Power and the Energy Efficiency Advisory Group[2] to evaluate and report upon the viability of Time-of-Use ("TOU") metering programs and the deployment of AMR[3] technology. Order No. 28894 at 7, Order No. 29026 at 22.

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[1] There are approximately 4,000 customers, who make up approximately 1 percent of total customers, whose electrical service comes from Idaho Power's 53 smallest distribution substations. The technology will work in these locations but the station infrastructure cost per customer is very high and is not offset by the benefits that would be achieved through AMI at this time. These customers are not currently included in the proposed deployment plan.

[2] The Energy Efficiency Advisory Group is made up of customers, Commission Staff, Company employees and technology specialists who advise and make recommendations regarding the evaluation, revision, and implementation of demand-side management ("DSM") programs to the Company. The Group is charged with recommending new DSM measures, enhancing existing DSM programs, prioritizing implementation of appropriate programs, and evaluating each program's effectiveness. Order No. 28894 at 2, 7.

[3] "AMR" refers to "Advanced Meter Reading" or "Automated Meter Reading." "AMI" refers to "Advanced Metering Infrastructure." AMI is a more inclusive term than AMR, and refers to systems that measure, collect, and analyze energy usage information from advanced metering devices through various communication media on

Case No. IPC-E-02-12 was opened to investigate TOU pricing for Idaho Power's residential customers and, after review of the Company's initial report, the Commission directed Idaho Power to implement AMI "as soon as possible, with installation commencing this year [2003] and completed in 2004." Order No. 29196 at 10. The Commission ordered Idaho Power to submit a plan no later the March 20, 2003, to replace the current meters of Idaho Power customers with advanced meters. *Id.* at 11. The 2004 implementation was subsequently delayed because of the financial, technical, and implementation problems encountered with meeting that time frame. Order No. 29226 at 2-3. The Commission then adopted a phased-in implementation along with a collaborative evaluation approach, while directing the Company to continue to work towards implementation of AMI technology "as soon as possible." Order No. 29362 at 12, Order No. 30102 at 5-6. The Commission has continually stated that Idaho Power should be working toward the implementation of AMI technology as soon as possible, and has reiterated its finding that "the potential benefits of advanced metering to ratepayers and the Company are too great to delay AMR implementation indefinitely." *Id.*

2. The Commission ordered that Idaho Power collaboratively develop and submit a Phase One AMR Implementation Plan to replace current residential meters in selected service areas by December 2003, complete Phase One installation by December 31, 2004, and file a Phase One implementation Status Report by the end of 2005. Order No. 29362. In December 2003, after a collaborative workshop amongst the Company, Commission Staff, vendors and interested individuals, the Company filed

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request or on a pre-defined schedule. This infrastructure includes hardware, software, communications equipment, customer associated systems, and data management software. The term "AMR" was upgraded to "AMI" as the technology and terminology developed. "AMI" better reflects the capabilities of the technology discussed herein.

its Phase One Implementation Plan to install AMI technology in the Emmett and McCall operating Areas. Case No. IPC-E-02-12. Phase One implementation was completed on October 26, 2004, and consisted of approximately 23,500 meters along with other associated infrastructure.

3. Subsequent to Phase One implementation, the Company instituted two time-variant pricing pilot programs in the Emmett operating area that utilized the hourly consumption data made possible by the AMI technology. Order No. 29737, Case No. IPC-E-05-02. The programs were (1) the Energy Watch Pilot Program, Schedule 4, and (2) the Time-of-Day Pilot Program, Schedule 5. *Id.* These pilots were subsequently authorized to continue indefinitely, as tariff Schedules 4 and 5, for continued development and further evaluation in anticipation of an eventual system-wide implementation of time-variant pricing and AMI technology. Order No. 30292, Case No. IPC-E-07-05. The Company is required to file annual reports detailing the previous year's progress for both programs. *Id.*

4. On December 30, 2005, the Phase One AMR Implementation Status Report was filed with the Commission and Noticed for Comments pursuant to Modified Procedure. Order No. 29959, Case No. IPC-E-06-01. The report detailed the implementation as well as the time-variant pricing pilots and load control AC cycling programs conducted with the AMI technology, and made recommendations for future evaluation and deployment. In this docket, the Commission granted the Company an additional one-year period in which to work to resolve technical issues encountered in the pilot programs, allow for the technology to mature, and to assess further AMI deployment while ordering an updated status report to be filed by May 1, 2007.

5. On May 1, 2007, the Company filed a detailed AMI Status Report, followed by an August 31, 2007, Implementation Plan describing and proposing a three-year deployment of an AMI system covering roughly 99 percent of the customers in its service territory from January 2009 through the end of 2011. Case No. IPC-E-06-01. This proceeding seeks approval of that plan.

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

6. Idaho Power proposes to install AMI throughout its service territory in a systematic, three-year deployment schedule starting in January 2009, and continuing through the end of 2011. The schedule would start with the Company's Capital Region (Boise, Meridian, Eagle, Kuna, etc.) in 2009, move to the Canyon and Payette Regions (Nampa, Caldwell, Payette, Ontario, etc.) in 2010, and finish with the Southern and Eastern Regions (Twin Falls, Hailey, Jerome, Pocatello, Salmon, etc.). A map showing the proposed deployment is included as Attachment No. 1 to this Application. The actual meter exchanges will take place on a carefully planned schedule that would generally follow meter reading routes, and progress route by route and substation by substation to install the required hardware throughout the system.

7. The system-wide implementation of AMI technology is cost effective at this time. The August 31, 2007, AMI Implementation Plan filed with the Commission in Case No. IPC-E-06-01 includes a summary of the Company's updated cost-benefit analysis, as directed by Order No. 30102, concluding that the long-term benefits derived from reduced operating expenses are themselves sufficient to support a system-wide implementation. This has not always been the case. *See*, Order No. 29362 at 11. Additionally, as recognized by the Commission in several Orders, the deployment of

AMI technology has numerous other benefits for the both the Company and its customers that cannot necessarily be quantified at this time, but never-the-less exist. *See*, Order No. 29196 at 10; Order No. 30102 at 5-6; Order No. 29362 at 12-14. The direct benefits that will increasingly be recognized following the start of the implementation are the operational savings associated with remote meter readings. Beyond the savings in meter reading costs and the benefits associated with time-of-use pricing, additional benefits as stated in the findings of this Commission are:

> AMR would improve meter reading accuracy, eliminate the need for Idaho Power to gain access to customer property for monthly meter reads, and allow Idaho Power to develop new services in the future. An AMR system would improve outage monitoring, theft detection, and employee safety. AMR's capacity for remote connects and disconnects would also save customer time and employee labor. From a billing perspective, AMR would result in fewer estimated bills, less rebilling, flexible billing schedules, account aggregating, and flexible rate designs.

Order No. 29196 at 10. The AMI technology selected for installation by the Company is a true two-way communications system that is fully capable of enabling the various other functionalities anticipated by the Commission, and mentioned above, as well as other "smart-grid" operations into the future. Outage management functionality and hourly data collection will be implemented for each area in the succeeding year following deployment. The benefits of outage management integration will begin to be realized almost immediately, although achieving the full benefit from hourly data collection will likely require more time as additional back office systems and rate structures will need to be in place before significant benefits could be realized through TOU pricing and rates.

8. The Company has selected vendors and executed contracts to secure the required hardware, software, and labor for this deployment through its Strategic Sourcing Process that involves both a Request for Information ("RFI") and a Request for Proposals ("RFP") process. The Strategic Sourcing Process utilizes a cross-functional team made up of Idaho Power employees with the assistance of a strategic sourcing consultant and is led by the Company's Procurement Department professionals. The team conducted the RFI and RFP process to evaluate and assess the possible AMI solutions and ultimately to select vendors and successfully negotiate contracts for the deployment of the AMI technology. The team is made up of employees with expertise in procurement/purchasing, pricing/regulatory, meter support, finance, and other subject matter experts.

9. Because of the evolving and developing nature of the AMI technology there is not a single-source vendor that can provide all of the necessary components required for an AMI deployment. Idaho Power has executed four contracts ("Agreements") with separate vendor companies that each provide a distinct product and/or service that is required to complete the supply chain necessary to install AMI. The contracted vendors (collectively, "AMI vendors") are: (1) Aclara Power-Line Systems Inc. ("Aclara"), formerly known as Distribution Control Systems Inc. ("DSCI"), to provide the Two-Way Automated Communication System ("TWACS®") which uses power line carrier communication technology, and primarily includes the AMI modules that are installed in the meters, software, substation control equipment, as well as support service, project management, and training; (2) Landis+Gyr Inc. ("Landis+Gyr"), to provide the residential meters including the integration of TWACS® modules from

Aclara into Landis+Gyr meters, providing electronic certified meter test results with each shipment, support services to manage the meter module integration and delivery, and meter/module failure analysis and resolution; (3) General Electric Company ("GE"), to provide the commercial meters including integration of TWACS® modules into GE meters, providing electronic certified meter test results with each shipment, support services to manage the meter module integration and delivery, and meter/module failure analysis and resolution; and (4) Tru-Check, Inc. ("Tru-Check"), to provide meter exchange services (remove and replace) and plan the logistics to provide: material management, project management, exchange order management, meter exchange resource management, and other services necessary to exchange meters on schedule in years 2008 – 2011.

10. Idaho Power is not requesting a rate increase with this filing. The Company requests in this proceeding that the Commission find the deployment of AMI technology to be in the public interest and grant the Company a Certificate of Public Convenience and Necessity to install AMI technology throughout its service territory. In granting the Company a CPCN, Idaho Power asks the Commission to state in its Order that, in the ordinary course of events, Idaho Power can expect to ratebase the prudent capital costs of deploying AMI as it is placed in service, accelerate the depreciation of the existing metering infrastructure replaced by AMI over the three-year deployment, and include the operation and maintenance benefits in the accounting methodology.

CAPITAL COST COMMITMENT ESTIMATE

11. Idaho Power has negotiated firm unit pricing in its contracts to acquire and deploy AMI technology over the three-year plan. Based upon these Agreements, Idaho

Power is able to make a reliable estimate of the total capital cost of the Project. This "Commitment Estimate" is a good faith estimate of the project's total capital cost based upon the contract pricing plus certain additional costs the Company knows it will incur but cannot quantify with precision at this time.

12. These additional costs include, but are not limited to, sales taxes, customer growth, fuel charges, additional Information Technology ("IT") hardware, software, and personnel time, and the cost of Idaho Power oversight of the Project. The Commitment Estimate also covers contingencies such as change orders and customer growth. Idaho Power's Commitment Estimate for the Project is $70.9 million.

13. The Commitment Estimate does not include the accelerated depreciation of the existing metering infrastructure or the operation and maintenance benefits associated with the installation of the AMI technology.

14. Idaho Power will commit to the initial acquisition and installation of AMI technology throughout its entire service territory as described in this proceeding for the Commitment Estimate. The Commitment Estimate would be subject to adjustment to account for documented, legally-required equipment changes and material changes in assumed escalation or growth rates not foreseen at the time of this Application. If the capital cost of the project exceeds the adjusted Commitment Estimate, Idaho Power will absorb the extra cost. The Company will include in its Idaho rate base only the amount actually incurred up to the adjusted Commitment Estimate.

MODIFIED PROCEDURE

15. In order to purchase certain equipment at competitive prices, to acquire long lead time equipment, and to get materials into the rather complex supply chain in

time for installation to begin in January 2009, Idaho Power has already ordered and purchased certain items, and must place additional orders in September and October of 2008. The cost of the equipment that has been ordered and purchased thus far is approximately $1.2 million. With the additional orders that must be placed in September/October 2008, the Company will be committing to an additional cost of approximately $5 million. Consequently the Company is requesting that this Application be processed expeditiously.

16. In order to streamline the process and expedite the Commission's review of the Application, the direct testimony of John R. Gale, Courtney Waites, and Mark Heintzelman in support of this Application is filed concurrently herewith. In addition, Idaho Power has assembled documents that it anticipates, based on prior CPCN cases, that Staff and any potential intervenors will likely desire to examine as part of their analysis of this Application. Additionally, the Company can make personnel available to meet with Staff and intervenors at Idaho Power to walk through, describe, and demonstrate the Strategic Sourcing Process. The Company will work with Staff and any intervenors to expedite the discovery/review process.

17. Some of the documents the Company intends to provide for review contain information that the bidders and selected AMI vendors deem to be confidential, commercially sensitive, and trade secrets. To assure full bidder participation in future Idaho Power RFPs, as well as to protect critical, confidential commercial information of the AMI vendors, the Company requests that Staff and any intervenors sign an appropriate confidentiality agreement prior to reviewing these materials, as has been

done in past cases. Hopefully, making these documents immediately available for review will help expedite the processing of this Application.

18. Idaho Power believes that a hearing is not necessary to consider the issues presented herein, and respectfully requests that this Application be processed under Modified Procedure, i.e., by written submissions rather than by hearing. RP 201 *et seq*. If, however, the Commission determines that a technical hearing is required, the Company stands ready to present its testimony and support the Application in such hearing.

COMMUNCIATIONS AND SERVICE OF PLEADINGS

19. Communications and Service of Pleadings with reference to this Application should be sent to the following:

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bkline@idahopower.com

Courtney Waites
John R. Gale
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cwaites@idahopower.com
rgale@idahopower.com

REQUEST FOR RELIEF

20. Idaho Power respectfully requests that the Commission issue an Order (1) authorizing that this matter may be processed by Modified Procedure, (2) granting the Company a Certificate of Public Convenience and Necessity to install Advanced Metering Infrastructure ("AMI") technology throughout its service territory, (3) authorizing that, in the ordinary course of events, Idaho Power can expect to ratebase the prudent capital costs of deploying AMI as it is placed in service, (4) authorizing the accelerated depreciation of the existing metering infrastructure replaced by AMI over the three-year

deployment, and (5) including the operation and maintenance benefits in the accounting methodology.

DATED at Boise, Idaho this 4th day of August 2008.

Donovan E. Walker
Attorney for Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-08-16

IDAHO POWER COMPANY

ATTACHMENT NO. 1

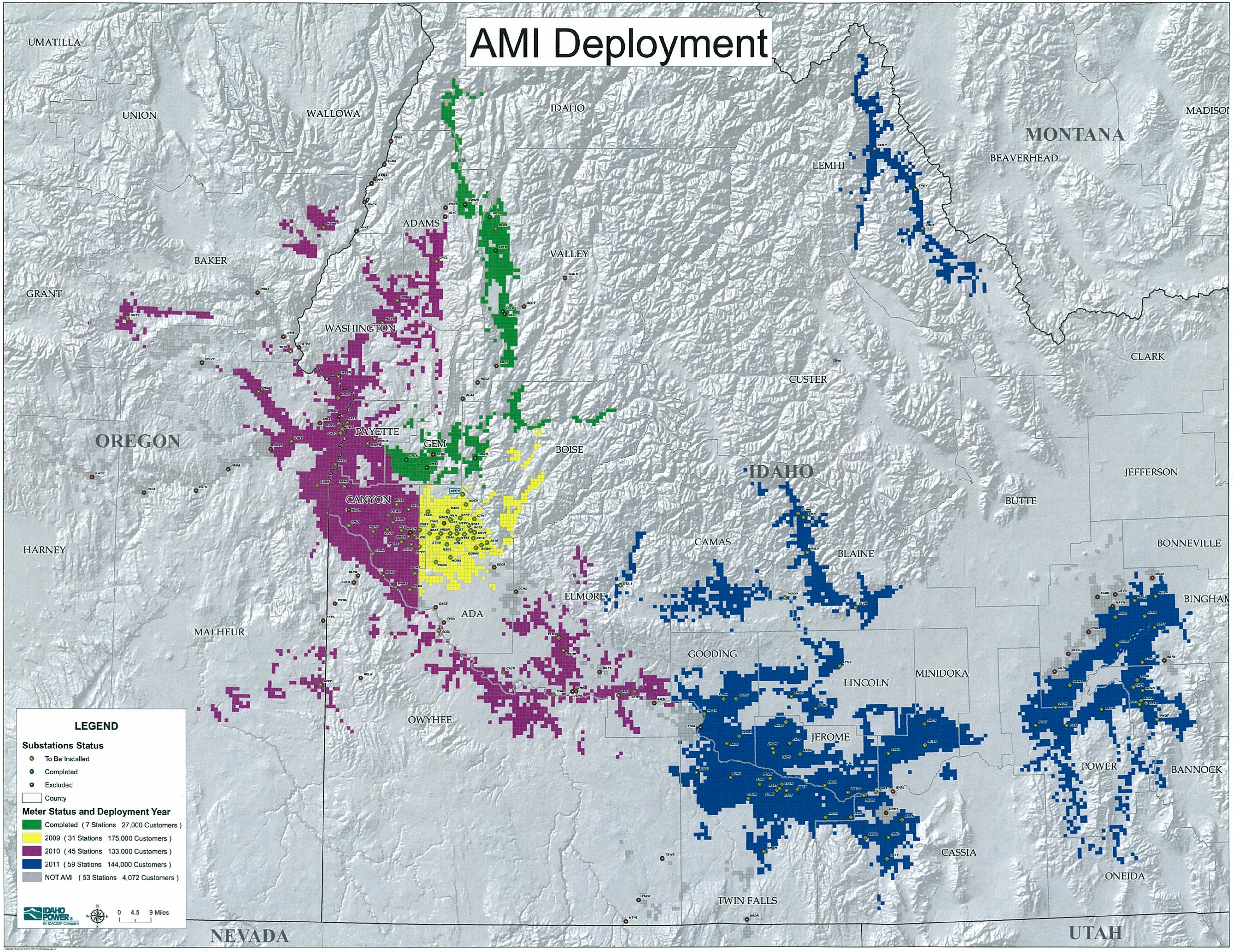
ATTACHMENT NO. 1

MAP NOT SCANABLE

(PLEASE SEE PAPER FILE)

ATTACHMENT NO. 3

Map Showing Proposed AMI Deployment


AMI Deployment
UMATILLA
UNION
WALLOWA
IDAHO
MONTANA
MADISON
BEAVERHEAD
LEMHI
ADAMS
VALLEY
BAKER
GRANT
WASHINGTON
CLARK
CUSTER
OREGON
PAYETTE
GEM
BOISE
IDAHO
JEFFERSON
BUTTE
CANYON
CAMAS
BLAINE
HARNEY
BONNEVILLE
ELMORE
BINGHAM
ADA
MALHEUR
GOODING
MINIDOKA
LINCOLN
OWYHEE
JEROME
POWER
BANNOCK
CASSIA
ONEIDA
TWIN FALLS
NEVADA
UTAH
LEGEND
Substations Status
To Be Installed
Completed
Excluded
County
Meter Status and Deployment Year
Completed (7 Stations 27,000 Customers)
2009 (31 Stations 175,000 Customers)
2010 (45 Stations 133,000 Customers)
2011 (59 Stations 144,000 Customers)
NOT AMI (53 Stations 4,072 Customers)
IDAHO POWER
0 4.5 9 Miles

ATTACHMENT NO. 4

Testimony of Mark C. Heintzelman (IPUC Case No. IPC-E-08-16)

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO INSTALL ADVANCED METERING INFRASTRUCTURE ("AMI") TECHNOLOGY THROUGHOUT ITS SERVICE TERRITORY	)	CASE NO. IPC-E-08-16

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MARK C. HEINTZELMAN

Q. Please state your name and business address.

A. My name is Mark C. Heintzelman 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 ("the Company") as Delivery Services Leader in the Metering area.

Q. Please describe your educational and relevant professional background.

A. I received electronics training in the United States Air Force at Keesler Air Force Base in 1976 and avionics systems training at Nellis Air Force Base in 1977. I attended Boise State University and completed its Utility Lineman program in 1982. I started working for Idaho Power in the Boise Metering Department in 1982. I have held positions with Idaho Power as a Journeyman Meterman, Metering Engineering Specialist, Journeyman Relay Technician, Meter Shop Forman, Corporate Metering Support Leader, and I am currently the Advanced Metering Infrastructure ("AMI") Implementation Project Leader.

I have completed courses in Industrial Electronics and the International Organization of Standards ("ISO") Quality Management System Implementation, and I have been certified as a Quality Systems Auditor.

I am a longtime member of the Automated Meter Reading Association ("AMRA") (recently changed to Utilimetrics, the Alliance for Advanced Metering & Data Management) and I serve on the advisory committee for the Western Energy Institute's Northwest Meter School. I have been an instructor for the Western Energy Institute's Relay School and Northwest Meter School. I have given technical presentations on advanced metering and meter data management at national conferences of AMRA, the Itron & TWACS User's conferences, and the Seattle Meter School.

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

A. My testimony will describe how the Company chose the Two-Way Automated Communication System ("TWACS") for its AMI technology; the Company's plan for deploying AMI technology throughout its system; how the system works, generally; some of the functionality and expected benefits from this AMI system; as well as a description of the contracts the Company has entered into with its AMI vendors.

Q. Could you please describe how Idaho Power selected the TWACS power line carrier technology from Aclara Power-Line Systems Inc. ("Aclara") for the system-wide deployment of AMI technology?

A. The Company's experience with the TWACS system goes back to 1998, when it deployed a pilot program consisting of 1,000 meters in the Idaho City area. The purpose of this program was to evaluate the system's ability to read meters in remote locations and determine the feasibility of deploying what was then Automated Meter Reading ("AMR") to reduce operating costs by automating the monthly meter reading process in low customer density areas.

In 2004, Idaho Power deployed the TWACS technology in the Emmett and McCall areas in conjunction with the Phase One Implementation Plan filed with the Commission in Case No. IPC-E-02-12. The Company also utilized this technology in its Energy Watch and Time-of-Day pilot programs for the Emmett Valley. With these programs the Company was able to evaluate the system's ability to gather hourly energy use data from all endpoints in support of dynamic time-of-use ("TOU") rate applications and evaluate the system's functionality related to direct load control through an air conditioner cycling program.

In November 2007, pursuant to the Company's August 31, 2007, AMI Implementation Plan filed in Case No. IPC-E-06-01, the Company formed a cross-functional team made up of Idaho Power employees with the assistance of a strategic sourcing consultant, and led by the Company's Procurement Department professionals, to evaluate and assess the possible AMI solutions and ultimately to select vendors and successfully negotiate contracts for the deployment of the AMI technology. This approach is part of the Company's Strategic Sourcing Process. The team is made up of employees with expertise in procurement/purchasing, pricing/regulatory, meter support, finance, and other subject matter experts. In 2008, the team issued a Request for Information ("RFI") to thirteen of the industry's leading AMI technology providers, including Aclara, for a system-wide deployment. The RFI requested specific information related to deployment scale, system functionality, and technology. The responses were evaluated against our system and functional requirements by a Strategic Sourcing team assembled for the AMI project, with an emphasis on specific demonstrated functionality at scale. The RFI evaluation reduced the field of thirteen AMI technology providers down to two.

The Company then issued a Request for Proposals ("RFP") to the two remaining technology providers, one of which was Aclara. The analysis of the proposals was performed by the same cross-functional Idaho Power team, again with the assistance of a strategic sourcing consultant. The proposals were evaluated against our functional requirements, financial requirements, and our physical electrical system requirements. The team concluded that the Aclara TWACS power line carrier system was the best match to our requirements and provided the best value to Idaho Power and its customers. Aclara's proposed solution demonstrated superior system performance at scale, the functional capability to retrieve hourly data at scale, and the proven ability to deliver successful system performance economically in low customer density applications.

Q. What is the Company's approach for deployment of AMI technology on a system-wide basis?

A. The Company's approach could be described in three parts, or Phases. Phase I is the determination of system capabilities as well as selection and evaluation of the appropriate AMI technology. Phase II is the actual deployment of the selected technology infrastructure, which would be the Company's three-year deployment plan. This plan was described in the August 31, 2007, Advanced Metering Infrastructure Implementation Plan filed with the Commission in Case No. IPC-E-06-01, and is the subject of this filing. Once the Phase II AMI deployment is completed, the Company will have a two-way communications system infrastructure in place with the potential to provide additional functionality and benefit. The additional functionality and systems implementation, as well as the additional benefit quantification of various programs and uses, would be Phase III of the AMI implementation.

Q. Could you please describe Idaho Power's proposed AMI implementation, or Phase II?

A. Idaho Power proposes to install AMI throughout its service territory in a systematic, three-year deployment schedule starting in January 2009 continuously through the end of 2011, with some preparations being implemented in late 2008. The schedule would start with the Company's Capital Region (Boise, Meridian, Eagle, Kuna, etc.) in 2009, move to the Canyon and Payette Regions (Nampa, Caldwell, Payette, Ontario, etc.) in 2010, and finish with the Southern and Eastern Regions (Twin Falls, Hailey, Jerome, Pocatello, Salmon, etc.).

In 2009, the Company will install the remaining substation infrastructure in Ada County and begin installation substation infrastructure in Canyon County. Idaho Power plans to complete meter deployments in Ada and Boise Counties in 2009. In 2010, the Company will complete substation infrastructure deployment and meter installations in our service territory west of Boise and in the Mountain Home Area and begin the installation of the substation infrastructure in the Pocatello area. In 2011, the Company will complete the AMI system installation in the eastern half of its service territory from the Pocatello area east through the Twin Falls area connecting back to the Mountain Home area. The actual meter exchanges will take place on a carefully planned schedule that would generally follow meter reading routes, and progress route by route and substation by substation to install the required hardware throughout the system.

Q. Does the proposed deployment cover the Company's entire service territory?

A. Yes. The deployment covers the entire service territory, and reaches approximately 99 percent of the Company's customers. There are approximately 4,000 customers, who make up approximately 1 percent of total customers, whose electrical service comes from Idaho Power's 53 smallest distribution substations. These customers are typically in the most remote edges of our service territory and are largely low or seasonal energy users. The TWACS technology will work in these locations but the station infrastructure cost per customer is very high and is not offset by the benefits that would be achieved through AMI at this time. The Company proposes to re-evaluate this situation at the completion of the Phase II deployment. At that time, a determination regarding whether AMI is appropriate for those remaining customers and what AMI technology would be most cost effective for deployment can be made. The locations of the 1 percent of customers that will not be covered is illustrated on the map provided as Attachment No. 1 to the Application in this case.

Q. What functionality and benefits will the AMI System provide?

A. As the technology is deployed area by area, we will implement the system to replace our monthly meter reading and customer movement meter reading process. This will begin to provide benefits in the first year of deployment by reducing operational and maintenance costs.

As each annual deployment is completed, additional functionality will be implemented in the succeeding year. We are planning to implement outage management functionality and hourly data collection at that time as well. The benefits of outage management integration will begin to be realized almost immediately. Achieving the full benefit from hourly data collection will likely require more time and the implementation of time variant rates at a significant scale. Additional back office systems and rate structures will need to be in place before significant benefit could be realized.

Q. Could you generally describe the AMI system being implemented by Idaho Power and how it works?

A. The TWACS AMI system uses the electrical distribution system as the path for two-way communications between the TWACS substation communications equipment and the endpoint communications modules installed internally in the customers' electric meters or load control devices. The software for the AMI System is hosted on the Idaho Power network. It consists of proprietary software applications, a hardware operating system, backup and test applications, communications applications and servers, and database applications and servers. The software application will be connected to the substation control equipment through our existing internal network or through the phone system.

The substation control equipment will be installed in our existing distribution substations. A typical installation would consist of a phone line with frame relay service, a phone protection package, a control receiver unit to provide the connection between software system and the station equipment and to control the operation of the station equipment, an outbound modulation unit to convert the data request to be transmitted across the electrical distribution system, a modulation transformer unit to inject the signal on the distribution system, and inbound pickup units to retrieve the data back from the endpoint communications modules.

The only equipment required on the electrical distribution system are the endpoint communications modules. The communications are modulated on the electricity flowing on the system and, therefore, no additional equipment is required between the substation and endpoints. Because of the unique method used by the TWACS system to modulate the electrical sine wave the signal requires no further modulation amplification and remains intact to the end of the electrical distribution system. Please see Exhibit No. 2 to my testimony for a diagram of this process. Idaho Power sees this feature as an extremely valuable attribute of the system. As we add new customers, the only equipment required to expand the existing communications system will be a communications module in the electric meter or end device.

Q. Could you give a brief description of how the AMI two-way automated communications system works?

A. Yes. Please refer to Exhibit No. 3 to my testimony for a simplified diagram of how the system is connected. Once the components of the system are installed, communications take place starting with the software initiating communications commands, typically on a predetermined schedule. The commands are processed through a communications server and sent out through our internal network or through a phone service provider to the appropriate distribution substation. At the substation, the communications command is received by the TWACS station equipment and sent out on the electrical distribution system. Each endpoint communications module (located in the meter) is uniquely identifiable and responds to requests for data only when specifically addressed by the system. When a communications module is addressed by the system, it will respond to the request by delivering the data requested in a predetermined format. There are typically data retrieval schedules for daily meter reads, predetermined blocks of hourly energy use data, and monthly billing reads. Once the substation control equipment has the information back from the individual communications modules, the data will automatically be sent back over the phone or network system to the TWACS network software. The data is then validated and moved to the system database.

The TWACS system has built in features to continually optimize the communications process, and in cases where you are retrieving hourly energy use information, it is best not to interfere with the systems automatic operations by making frequent direct unscheduled data requests from individual communications modules. Direct unscheduled communications will be limited to troubleshooting and necessary maintenance communications. This will allow the system to optimize communications and data retrieval performance.

Q. Could you describe the contracts that the Company has entered into for the AMI implementation?

A. Because of the evolving and developing nature of the AMI technology, there is not one single source vendor that can provide all of the necessary components required for an AMI deployment. Idaho Power has executed four contracts with separate vendor companies that each provide a distinct product and/or service that is required to complete the supply chain necessary to install AMI.

The contracted vendors (collectively, "AMI vendors") are: (1) Aclara Power-Line Systems Inc., formerly known as Distribution Control Systems Inc. ("DSCI"), to provide their Two-Way Automated Communication System (called

"TWACS®") which uses power line carrier communication technology, and primarily includes the AMI modules that are installed in the meters, software, substation control equipment, as well as support service, project management, and training; (2) Landis+Gyr Inc. ("Landis+Gyr"), to provide the residential meters, including the integration of TWACS® modules from Aclara into Landis+Gyr meters, providing electronic certified meter test results with each shipment, support services to manage the meter module integration and delivery, and meter/module failure analysis and resolution; (3) General Electric Company ("GE"), to provide the commercial meters, including integration of TWACS® modules into GE meters, providing electronic certified meter test results with each shipment, support services to manage the meter module integration and delivery, and meter/module failure analysis and resolution; and (4) Tru-Check, Inc. ("Tru-Check"), to provide meter exchange services (remove and replace) and plan the logistics to provide material management, project management, exchange order management, meter exchange resource management, and other services necessary to exchange meters on schedule in years 2008 - 2011.

Q. Could you describe how the Supply Chain works for the AMI deployment?

A. The process essentially starts with Aclara, who will provide the necessary system software and substation control equipment directly to Idaho Power, with the exception of some Information Technology hardware (servers) and the substation modulation transformers. Idaho Power will purchase servers and transformers directly from our preferred suppliers for those products. Substation Control Equipment has an approximate 22-week lead time.

The AMI communications modules, from Aclara, will be installed internally by the meter manufacturers into new solid-state electrical meters. These modules will be shipped from Aclara's manufacturing facilities directly to Landis+Gyr and GE, the meter manufacturers. At the time of meter manufacture, the meter providers will integrate the TWACS communications module into the electric meters. The meter manufacturers will then ship the AMI equipped meter as a unit to Idaho Power's contracted meter exchange service provider, Tru-Check. The AMI modules are ordered with a 17-week lead time, and meters are ordered with a 13-week lead time.

Tru-Check will physically receive the meter shipments on a predetermined schedule. Upon receipt, they will notify Idaho Power and segregate the shipment until validated and released for use by Idaho Power. Tru-Check will both uninstall the old meter and install the AMI equipped meter on a meter exchange route established by Idaho Power and TruCheck a minimum of 120 days in advance of the meter exchange. Tru-Check will be responsible for receipt, handling, and storage of meters and materials; removal and return of old meters; installation and verification of new meters; and the validation of data from the new meters.

Q. Could you describe the pricing and terms that were negotiated with the AMI vendors?

A. The specific pricing and terms of the contracts are deemed highly sensitive, confidential commercial information by the AMI vendors. As such, the following information is provided in general terms. Additional details are available to the Commission and Commission Staff as confidential information pursuant to a signed Protective Agreement.

Idaho Power was able to obtain fixed unit pricing from all AMI vendors to cover at least the duration of the three-year deployment. For Aclara, pricing for modules is fixed for a period of five years. For Landis+Gyr, pricing for residential meters is fixed for a period of five years. For GE, pricing for commercial meters is fixed for a period of three years. For Tru-Check, pricing is fixed by region and paid only for each metered service point in which a "Successful Meter Exchange" is performed. A Successful Meter Exchange is defined as completing all of the following: contractor's receipt of new meter and associated materials as well as the subsequent storage and handling of the materials up to meter installation; removal of the existing meter and its return to Idaho Power without damage; installation and operation verification of new meter; accurate reading and recording of applicable meter reading data of both existing and new meter; and the completion of meter data transfer to Idaho Power and successful validation test.

Three year warranties are provided on all equipment from Aclara, Landis+Gyr, and GE. All pricing is unit pricing, essentially limiting the Company's exposure to the approximate four-month lead times on orders. All contracts also contain termination provisions whereby Idaho Power may terminate the contracts if regulatory approval is not received from the Commission.

The Company was able to successfully take advantage of its Strategic Sourcing Process and negotiate favorable terms and pricing for this AMI implementation. Pricing in most instances was negotiated lower than initial projections and expectations. The Company is confident that the process has resulted in a favorable environment that will lead to the successful implementation of AMI throughout its system.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

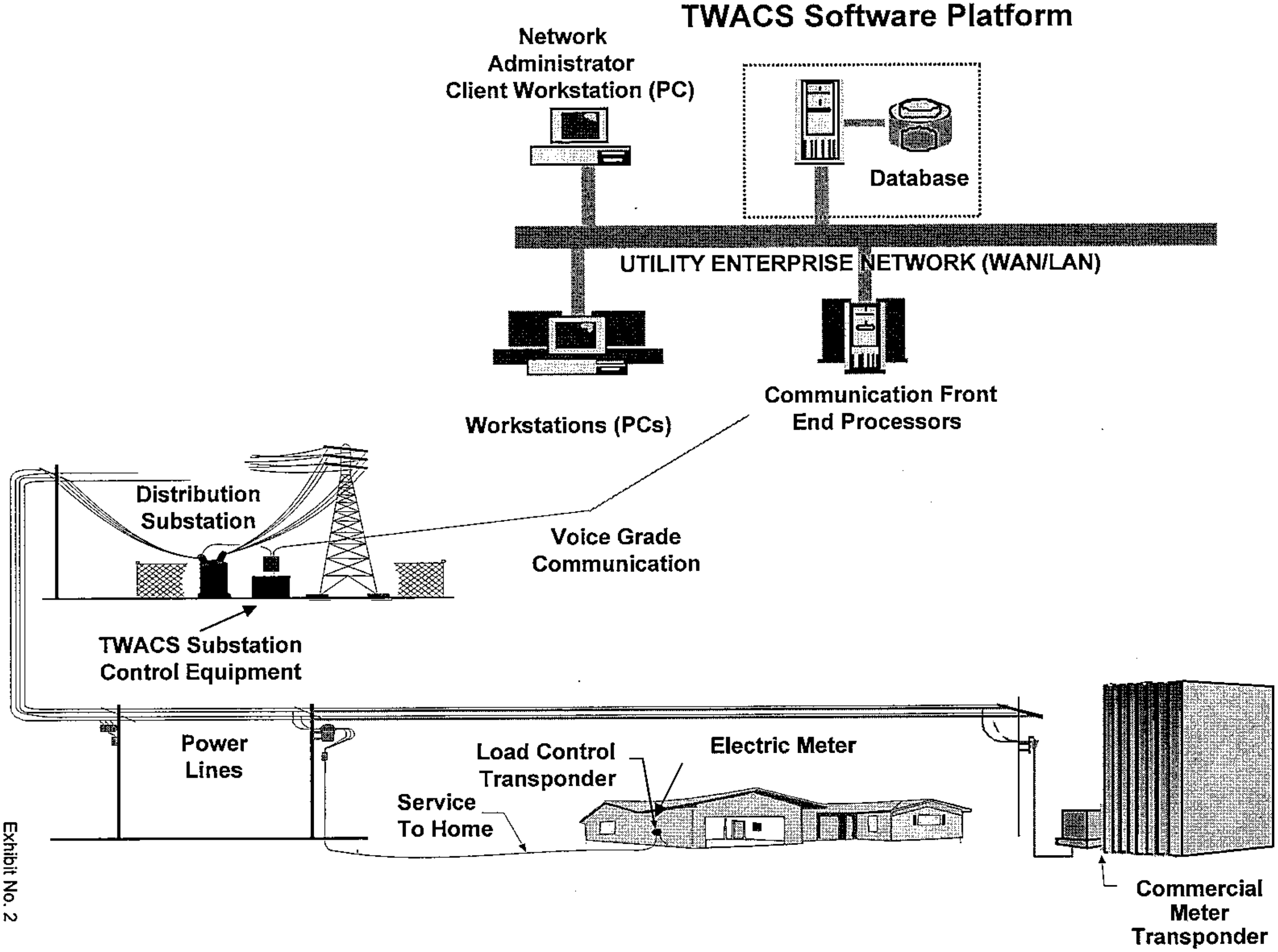
CASE NO. IPC-E-08-16

IDAHO POWER COMPANY

HEINTZELMAN, DI
TESTIMONY

EXHIBIT NO. 2

Idaho Power's Purposed TWACS System Overview



BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

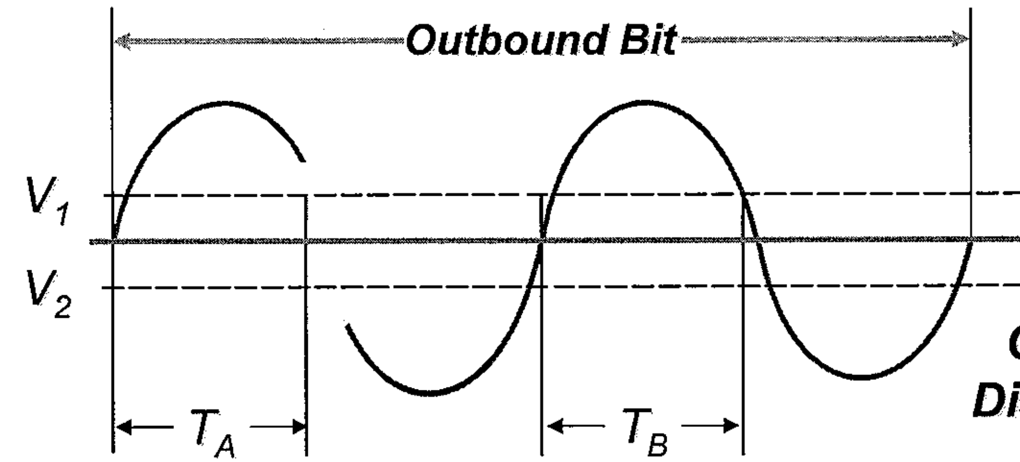
CASE NO. IPC-E-08-16

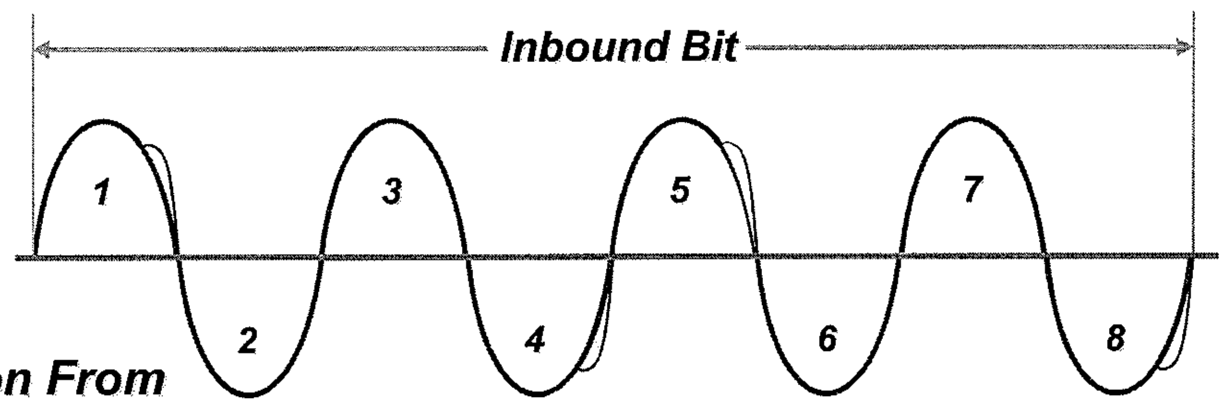
IDAHO POWER COMPANY

HEINTZELMAN, DI
TESTIMONY

EXHIBIT NO. 3

TWACS Communications





ATTACHMENT NO. 5

Application to Institute Revised Depreciation Rates for Electric Plant in Service (IPUC Case No. IPC-E-08-06)

IDAHO POWER®
An IDACORP Company

RECEIVED
2008 APR -1 PM 3:
IDAHO PUBLIC
UTILITIES COMMISSION

LISA D. NORDSTROM
Attorney II

April 1, 2008

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P. O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-08-06
IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INSTITUTE REVISED DEPRECIATION RATES FOR ELECTRIC PLANT IN SERVICE

Dear Ms. Jewell:

Please find enclosed for filing an original and seven (7) copies of the Company's Application for authority to institute revised depreciation rates for electric plant in service. Also enclosed are nine (9) copies of the testimony and exhibit of John J. Spanos, with one copy designated as the Reporter's Copy. A computer disc containing Mr. Spanos' testimony is also enclosed. Please note that Mr. Spanos' exhibit exceeds 400 pages. However, the testimony and exhibit are available as a pdf file.

I would appreciate it if you would return a stamped copy of this transmittal letter in the enclosed self-addressed, stamped envelope.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

BLK:sh
Enclosures

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2008 APR -1 PM 3:51
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INSTITUTE REVISED DEPRECIATION RATES FOR ELECTRIC PLANT IN SERVICE	CASE NO. IPC-E-08-06 APPLICATION

Idaho Power Company ("Idaho Power" or "Company"), pursuant to I.C. § 61-525 and RP 052 hereby applies to the Idaho Public Utilities Commission ("Commission") for an accounting order authorizing the Company to institute revised depreciation rates for the Company's electric plant in service effective August 1, 2008.

In support of this Application, Idaho Power presents the following:

1. The Company is not requesting a change in its electric rates. This request is for an accounting order approving revised depreciation rates for the Company to apply prospectively to its depreciable plant in service.

2. The last major changes to the Company's depreciation rates occurred October 22, 2003 as a result of Order No. 29363 issued in Case No. IPC-E-03-07. The revised depreciation rates proposed by the Company in this case are based on the results of a detailed depreciation study authorized by the Company and conducted by Gannett Fleming, Inc. relative to Idaho Power's electric plant in service as of December 31, 2006 ("the Study"). The Study updates net salvage percents and service life estimates for all plant assets. The Study is Exhibit 1 to the direct testimony of Gannett Fleming Inc.'s Vice President, John Spanos, which is included with this filing.

3. Idaho Power's current depreciation rates have been applied to the investment in each primary and sub-plant account. These depreciation rates are based on the straight line, remaining life method, location life basis (life span technique) for production plant and the straight line, remaining life method for transmission and distribution plant and amortization of certain general plant accounts. A summary schedule detailing the December 31, 2006 original plant cost, depreciation accrual amount and rate is set forth in Attachment 1.

4. The proposed depreciation rates for Idaho Power (Attachment 1) are based on plant accounting data available as of December 31, 2006. Gannett Fleming was asked to identify and measure changes, and recommend depreciation rates. The proposed depreciation rates are also based on the straight line, remaining life method, Average Service Life procedure ("ASL") for all electric plant.

5. Based on depreciable electric plant in service at December 31, 2006 of $3,467,925,739, the requested changes in depreciation rates would result in a $6,713,451 decrease in the total annual depreciation expense. Approximately $6.2

million of the decrease in depreciation expense is allocated to the Company's Idaho operations.

6. A depreciation "method" is a way in which it is determined how an asset with a finite life will lose value over time. The straight line, remaining life method is arguably one of the simplest where an asset is assumed to depreciate equally each year over its remaining service life. When more than a single item of property is under consideration, a grouping "procedure" is appropriate because all of the items within a group normally do not have identical service lives. Two types of depreciation "procedure" options are now discussed in more detail.

7. In conducting the Study, Gannett Fleming recommended the use of the Equal Life Group procedure ("ELG"). ELG is a group method of depreciation whereby property groups are subdivided according to service life (i.e. each equal life group includes property with the same life span), thus eliminating the need to base depreciation rates on the average service life of the assets. Under the ELG procedure, the full cost of short-lived items is accrued during their lives and more accurately reflects the timing of its diminution in value, leaving no deferral of accruals required to be added to the annual cost associated with long-lived items. As an example, assume a new property group is comprised of two assets each valued at $5000 with estimated service lives of 5 years and 25 years, respectively. The first asset depreciates at a 20% rate equaling $1000 in annual straight line depreciation expense. The second asset depreciates at a 4% rate equaling $200 in annual straight line depreciation expense. In the first year, the $1,200 in total depreciation expenses results in a 12% ($1,200 / $10,000) depreciation rate for the property group when viewed in its entirety.

8. The Company requested that Gannett Fleming prepare alternative depreciation rates based on the Average Service Life ("ASL") procedure. ASL is a group method of depreciation whereby the rate of annual depreciation is based on the average service life or average remaining service life of the group. This rate is applied to the surviving balances of the asset group's costs. Assuming the same scenario as outlined above, the ASL procedure would aggregate all the assets in the property group before computing annual depreciation expense. In other words, instead of the two $5000 assets depreciating at separate rates, the ASL procedure would assume the $10,000 in combined assets had an average life of 15 years [(5 years + 25 years)/2]. With an average annual straight line depreciation rate of 6.67% (100% / 15), the annual depreciation expense for this property group would be only $667 ($10,000 * 6.67%) in the first year. As compared to the ELG procedure, the ASL procedure tends to lengthen asset category service lives and thus reduce depreciation and depreciation reserves in the early years. This effect can be seen in the comparison of ELG and ASL procedures included as Attachment 2.

9. Based on depreciable electric plant in service on December 31, 2006 of $3,467,925,739, use of the ELG procedure would increase the Company's total annual depreciation expense by approximately $16.2 million more than use of the ASL procedure. The portion of the increase allocated to the Company's Idaho operations would be approximately $15.0 million. Although Idaho Power agrees with Gannett Fleming's recommendation that ELG is the superior procedure for determining depreciation accrual rates, the Company recognizes that ELG is more costly to ratepayers in the near-term and that the Commission recently approved new

depreciation rates for Avista Corp. and Rocky Mountain Power using the ASL procedure in Order Nos. 30498 and 30499. The Company believes the proposed depreciation changes using the Average Service Life procedure are reasonable and appropriate. Therefore, despite its preference for the ELG procedure, Idaho Power is proposing use of the ASL procedure in this proceeding.

10. Simultaneous with the filing of this Application, the Company has filed its direct case consisting of the testimony and exhibit of witness John J. Spanos. The Company stands ready for immediate consideration of this Application.

MODIFIED PROCEDURE

11. Idaho Power believes that a hearing is not necessary to consider the issues presented herein, and respectfully requests that this Application be processed under Modified Procedure, i.e., by written submissions rather than by hearing. *RP 201 et seq.* If however, the Commission determines that a technical hearing is required, the Company stands ready to present its testimony and support the Application in such hearing.

COMMUNICATIONS AND SERVICE OF PLEADINGS

12. Service of pleadings, exhibits, orders and other documents relating to this proceeding should be served on the following:

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jbowman@idahopower.com
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REQUEST FOR RELIEF

13. Idaho Power Company respectfully requests that the Commission issue an Order approving the revised depreciation rates, with such revised depreciation rates to become effective August 1, 2008.

DATED at Boise, Idaho this 1st day of April, 2008.

Lisa D. Nordstrom

LISA D. NORDSTROM

ATTACHMENT 1

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT									
	STEAM PRODUCTION PLANT									
310.20	LAND AND WATER RIGHTS	75-R4	*	0	203,015.26	133,168	69,847	3,674	1.81	19.0
311.00	STRUCTURES AND IMPROVEMENTS									
	Boardman	100-S1	*	(10)	13,664,764.34	10,401,832	4,629,409	204,502	1.50	22.6
	Jim Bridger	100-S1	*	(10)	63,198,974.93	46,843,278	22,675,593	1,198,753	1.90	18.9
	Valmy Unit 1	100-S1	*	(10)	29,417,622.31	21,939,527	10,419,858	442,158	1.50	23.6
	Valmy Unit 2	100-S1	*	(10)	24,255,332.32	15,671,964	11,008,903	402,266	1.66	27.4
	Total Account 311				*130,536,693.90*	*94,856,601*	*48,733,763*	*2,247,679*	*1.72*	*21.7*
312.10	BOILER PLANT EQUIPMENT - SCRUBBERS									
	Jim Bridger	60-R3	*	(5)	58,908,365.65	41,166,395	20,687,389	1,100,601	1.87	18.8
	Valmy Unit 2	60-R3	*	(5)	20,941,250.57	13,659,862	8,328,451	316,666	1.51	26.3
	Total Account 312.1				*79,849,616.22*	*54,826,257*	*29,015,840*	*1,417,267*	*1.77*	*20.5*
312.20	BOILER PLANT EQUIPMENT - OTHER									
	Boardman	70-R1.5	*	(5)	35,288,034.40	24,991,899	12,060,537	547,888	1.55	22.0
	Jim Bridger	70-R1.5	*	(5)	229,201,271.84	121,268,927	119,392,411	6,418,641	2.80	18.6
	Valmy Unit 1	70-R1.5	*	(5)	76,723,967.25	48,681,408	31,878,757	1,391,327	1.81	22.9
	Valmy Unit 2	70-R1.5	*	(5)	80,418,334.11	49,735,349	34,703,902	1,325,456	1.65	26.2
	Total Account 312.2				*421,631,607.60*	*244,677,583*	*198,035,607*	*9,683,312*	*2.30*	*20.5*
312.30	BOILER PLANT EQUIPMENT - RAILCARS									
	Boardman	25-R3		20	1,498,563.91	592,002	606,849	44,194	2.95	13.7
	Jim Bridger	25-R3		20	2,478,477.91	1,350,060	632,722	57,260	2.31	11.1
	Total Account 312.3				*3,977,041.82*	*1,942,062*	*1,239,571*	*101,454*	*2.55*	*12.2*
314.00	TURBOGENERATOR UNITS									
	Boardman	50-S0.5	*	(5)	12,082,591.21	6,914,586	5,772,136	282,044	2.33	20.5
	Jim Bridger	50-S0.5	*	(5)	68,938,574.30	32,920,951	39,464,553	2,248,580	3.26	17.6
	Valmy Unit 1	50-S0.5	*	(5)	17,109,524.14	11,887,785	6,077,214	301,882	1.76	20.1
	Valmy Unit 2	50-S0.5	*	(5)	24,455,252.30	15,405,938	10,272,077	449,977	1.84	22.8
	Total Account 314				*122,585,941.95*	*67,129,260*	*61,585,980*	*3,282,483*	*2.68*	*18.8*
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	Boardman	65-S1.5	*	0	4,099,075.54	3,187,420	911,655	42,951	1.05	21.2
	Jim Bridger	65-S1.5	*	0	25,368,186.72	20,271,169	5,097,019	286,647	1.13	17.8
	Valmy Unit 1	65-S1.5	*	0	15,908,284.23	11,276,003	4,632,281	208,945	1.31	22.2
	Valmy Unit 2	65-S1.5	*	0	15,983,662.93	10,012,750	5,970,914	232,254	1.45	25.7
	Total Account 315				*61,359,209.42*	*44,747,342*	*16,611,869*	*770,797*	*1.26*	*21.6*

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Boardman	50-R0.5	*	(5)	1,695,292.87	839,166	940,893	45,979	2.71	20.5
	Jim Bridger	50-R0.5	*	(5)	4,859,302.37	3,107,280	1,994,989	114,144	2.35	17.5
	Valmy Unit 1	50-R0.5	*	(5)	3,066,769.39	1,784,820	1,435,289	68,204	2.22	21.0
	Valmy Unit 2	50-R0.5	*	(5)	1,686,053.18	905,737	864,619	36,244	2.15	23.9
	Total Account 316				*11,307,417.81*	*6,637,003*	*5,235,790*	*264,571*	*2.34*	*19.8*
316.10	MISCELLANEOUS POWER PLANT EQUIPMENT - AUTOMOBILES	10-L2.5		25	58,859.95	1,746	42,399	5,601	9.52	7.6
316.40	MISCELLANEOUS POWER PLANT EQUIPMENT - SMALL TRUCKS									
	Jim Bridger	10-L2.5		25	208,142.12	180,864	(24,757)	0	-	-
	Valmy Unit 1	10-L2.5		25	18,003.44	15,151	(1,648)	0	-	-
	Total Account 316.4				*226,145.56*	*196,015*	*(26,405)*	*0*	-	-
316.50	MISCELLANEOUS POWER PLANT EQUIPMENT - MISCELLANEOUS									
	Boardman	10-L2.5		25	41,585.39	6,149	25,040	2,900	6.97	8.6
	Jim Bridger	10-L2.5		25	23,360.90	10,238	7,283	958	4.10	7.6
	Valmy Unit 1	10-L2.5		25	59,433.94	16,251	28,324	3,529	5.94	8.0
	Total Account 316.5				*124,380.23*	*32,638*	*60,647*	*7,387*	*5.94*	*8.2*
316.70	MISCELLANEOUS POWER PLANT EQUIP.-LARGE TRUCKS	19-S2		25	251,360.52	25,575	162,945	9,760	3.88	16.7
316.80	MISCELLANEOUS POWER PLANT EQUIP.-POWER OPERATED EQ	16-S0		30	1,114,431.30	(579,840)	1,359,943	145,714	13.08	9.3
	TOTAL STEAM PRODUCTION PLANT				**833,225,721.54**	**514,625,410**	**362,127,796**	**17,939,699**	**2.15**	
	HYDRAULIC PRODUCTION PLANT									
331.00	STRUCTURES AND IMPROVEMENTS									
	Hagerman Maintenance Shop	100-R2.5	*	(25)	1,558,200.45	588,724	1,359,027	64,117	4.11	21.2
	Milner Dam	100-R2.5	*	(25)	814,224.25	230,854	786,926	13,990	1.72	56.3
	Niagara Springs Hatchery	100-R2.5	*	(25)	5,029,555.80	1,275,880	5,011,064	179,766	3.57	27.9
	Hells Canyon Maintenance Shop	100-R2.5	*	(25)	1,604,833.95	566,934	1,439,107	51,501	3.21	27.9
	Rapid River Hatchery	100-R2.5	*	(25)	2,402,683.49	928,540	2,074,814	74,310	3.09	27.9
	American Falls	100-R2.5	*	(25)	11,857,401.29	6,038,675	8,783,073	197,107	1.66	44.6
	Brownlee	100-R2.5	*	(25)	30,068,208.63	17,491,534	20,093,727	726,270	2.42	27.7
	Bliss	100-R2.5	*	(25)	666,848.63	400,703	432,861	17,049	2.56	25.4
	Cascade	100-R2.5	*	(25)	7,364,153.73	3,051,973	6,153,221	123,336	1.67	49.9
	Clear Lake	100-R2.5	*	(25)	193,278.70	178,418	63,181	6,072	3.14	10.4
	Hells Canyon	100-R2.5	*	(25)	2,403,495.64	894,612	2,109,757	76,124	3.17	27.7
	Lower Malad	100-R2.5	*	(25)	600,746.78	373,630	377,303	15,214	2.53	24.8
	Lower Salmon	100-R2.5	*	(25)	888,303.03	527,177	583,200	22,849	2.57	25.5
	Milner	100-R2.5	*	(25)	9,512,589.19	2,729,102	9,161,634	159,676	1.68	57.4
	Oxbow Hatchery	100-R2.5	*	(25)	1,472,035.50	726,845	1,113,198	40,052	2.72	27.8
	Oxbow	100-R2.5	*	(25)	9,830,938.42	4,836,770	7,451,902	273,365	2.78	27.3
	Oxbow Common	100-R2.5	*	(25)	111,952.27	111,952	27,988	1,038	0.93	27.0
	Pahsimerio Accum. Ponds	100-R2.5	*	(25)	4,187,993.72	299,623	4,935,370	175,424	4.19	28.1
	Pahsimerio Trapping	100-R2.5	*	(25)	935,129.61	547,693	621,219	22,406	2.40	27.7

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

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	Shoshone Falls	100-R2.5	*	(25)	1,139,956.09	668,822	756,120	32,266	2.83	23.4
	STRUCTURES AND IMPROVEMENTS, cont.									
	Strike	100-R2.5	*	(25)	2,789,968.67	1,649,271	1,838,190	76,335	2.74	24.1
	Swan Falls	100-R2.5	*	(25)	25,223,735.85	6,914,133	24,615,536	753,550	2.99	32.7
	Twin Falls	100-R2.5	*	(25)	661,285.30	316,699	509,908	15,857	2.40	32.2
	Twin Falls (New)	100-R2.5	*	(25)	10,146,761.46	2,678,549	10,004,903	301,443	2.97	33.2
	Thousand Springs	100-R2.5	*	(25)	327,624.51	327,625	81,903	32,909	10.04	2.5
	Upper Malad	100-R2.5	*	(25)	357,819.86	274,952	172,323	7,041	1.97	24.5
	Upper Salmon A	100-R2.5	*	(25)	859,310.39	566,928	507,208	20,532	2.39	24.7
	Upper Salmon B	100-R2.5	*	(25)	326,935.58	151,070	257,600	10,033	3.07	25.7
	Upper Salmon Common	100-R2.5	*	(25)	352,331.39	153,746	286,668	11,100	3.15	25.8
	Total Account 331				*133,688,302.18*	*55,501,434*	*111,608,931*	*3,500,732*	*2.62*	*31.9*
332.10	RESERVOIRS, DAMS AND WATERWAYS - RELOCATION									
	Brownlee	90-S4	*	(20)	8,639,663.66	4,592,743	5,774,853	212,233	2.46	27.2
	Hells Canyon	90-S4	*	(20)	940,788.93	462,648	666,299	24,487	2.60	27.2
	Oxbow	90-S4	*	(20)	56,309.00	29,019	38,552	1,417	2.52	27.2
	Oxbow Common	90-S4	*	(20)	1,927,919.83	1,224,350	1,089,153	39,664	2.06	27.5
	Brownlee Common	90-S4	*	(20)	7,895,824.78	5,019,821	4,455,169	163,733	2.07	27.2
	Total Account 332.1				*19,460,506.20*	*11,328,581*	*12,024,026*	*441,534*	*2.27*	27.2
332.20	RESERVOIRS, DAMS AND WATERWAYS									
	Milner Dam	90-S4	*	(20)	614,874.97	172,994	564,856	9,559	1.55	59.1
	American Falls	90-S4	*	(20)	4,242,904.39	2,438,545	2,652,940	57,114	1.35	46.5
	Brownlee	90-S4	*	(20)	52,631,542.49	31,583,559	31,574,292	1,143,926	2.17	27.6
	Bliss	90-S4	*	(20)	7,480,783.71	5,874,296	3,102,646	131,012	1.75	23.7
	Cascade	90-S4	*	(20)	3,145,630.46	1,335,517	2,439,240	46,756	1.49	52.2
	Clear Lake	90-S4	*	(20)	584,984.73	450,439	251,543	24,200	4.14	10.4
	Hells Canyon	90-S4	*	(20)	51,724,316.81	25,151,853	36,917,327	1,316,438	2.55	28.0
	Lower Malad	90-S4	*	(20)	2,078,537.32	1,484,241	1,010,005	41,380	1.99	24.4
	Lower Salmon	90-S4	*	(20)	6,602,823.37	4,705,338	3,218,051	134,181	2.03	24.0
	Milner	90-S4	*	(20)	16,532,174.93	4,635,107	15,203,504	252,333	1.53	60.3
	Oxbow	90-S4	*	(20)	30,319,404.87	16,297,679	20,085,606	731,526	2.41	27.5
	Oxbow Common	90-S4	*	(20)	9,871.65	4,162	7,684	269	2.72	28.6
	Shoshone Falls	90-S4	*	(20)	512,401.48	478,649	136,233	8,809	1.72	15.5
	Strike	90-S4	*	(20)	9,764,915.58	7,374,540	4,343,360	187,848	1.92	23.1
	Swan Falls	90-S4	*	(20)	13,641,458.81	5,426,542	10,943,208	329,280	2.41	33.2
	Twin Falls	90-S4	*	(20)	263,089.08	203,663	112,044	4,996	1.90	22.4
	Twin Falls (New)	90-S4	*	(20)	7,669,627.33	1,604,132	7,599,420	223,512	2.91	34.0
	Thousand Springs	90-S4	*	(20)	2,083,442.82	2,083,443	416,690	167,517	8.04	2.5
	Upper Malad	90-S4	*	(20)	1,292,528.44	1,009,149	541,886	23,284	1.80	23.3
	Upper Salmon A	90-S4	*	(20)	1,153,590.73	342,659	1,041,650	42,594	3.69	24.5
	Upper Salmon B	90-S4	*	(20)	2,758,487.94	1,945,794	1,364,392	56,122	2.03	24.3
	Upper Salmon Common	90-S4	*	(20)	730,039.01	462,019	414,028	17,944	2.46	23.1
	Hells Canyon Common	90-S4	*	(20)	3,723,168.70	2,606,285	1,861,518	65,487	1.76	28.4
	Total Account 332.2				*219,560,599.62*	*117,670,605*	*145,802,123*	*5,016,087*	*2.28*	29.1
332.30	RESERVOIRS, DAMS AND WATERWAYS - NEZ PERCE	Square	*	0	5,599,934.61	1,006,639	4,593,296	160,717	2.87	28.6

IDAHO POWER COMPANY
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CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	Milner Dam	80-R3	*	(5)	878,005.87	210,871	711,035	13,153	1.50	54.1
	American Falls	80-R3	*	(5)	26,401,757.45	12,972,335	14,749,510	351,166	1.33	42.0
	Brownlee	80-R3	*	(5)	41,621,633.25	24,952,949	18,749,765	692,584	1.66	27.1
	Bliss	80-R3	*	(5)	4,367,360.46	2,949,965	1,635,762	69,661	1.60	23.5
	Cascade	80-R3	*	(5)	9,087,779.30	3,388,774	6,153,395	130,379	1.43	47.2
	Clear Lake	80-R3	*	(5)	742,499.27	82,179	697,446	66,717	8.99	10.5
	Hells Canyon	80-R3	*	(5)	10,936,002.51	3,941,566	7,541,238	284,219	2.60	26.5
	Lower Malad	80-R3	*	(5)	528,365.79	390,110	164,673	7,357	1.39	22.4
	Lower Salmon	80-R3	*	(5)	4,472,826.76	3,222,402	1,474,065	63,203	1.41	23.3
	Milner	80-R3	*	(5)	23,352,421.08	5,440,945	19,079,097	347,172	1.49	55.0
	Oxbow	80-R3	*	(5)	10,849,416.56	5,703,638	5,688,249	219,701	2.03	25.9
	Shoshone Falls	80-R3	*	(5)	1,624,269.34	749,464	956,018	41,504	2.56	23.0
	Strike	80-R3	*	(5)	4,674,860.58	3,215,915	1,692,689	74,596	1.60	22.7
	Swan Falls	80-R3	*	(5)	25,775,660.82	6,244,039	20,820,406	638,355	2.48	32.6
	Twin Falls	80-R3	*	(5)	1,430,443.99	257,847	1,244,119	38,915	2.72	32.0
	Twin Falls (New)	80-R3	*	(5)	15,678,462.57	3,498,786	12,963,600	391,295	2.50	33.1
	Thousand Springs	80-R3	*	(5)	729,122.94	521,519	244,062	98,241	13.47	2.5
	Upper Malad	80-R3	*	(5)	476,485.37	333,132	167,178	7,249	1.52	23.1
	Upper Salmon A	80-R3	*	(5)	1,191,919.73	607,043	644,472	26,398	2.21	24.4
	Upper Salmon B	80-R3	*	(5)	2,621,614.05	739,588	2,013,106	78,786	3.01	25.6
	Total Account 333				*187,440,907.69*	*79,423,067*	*117,389,885*	*3,640,651*	*1.94*	32.2
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	Hagerman Maintenance Shop	50-R1.5	*	(5)	39,066.76	8,428	32,592	1,635	4.19	19.9
	Milner Dam	50-R1.5	*	(5)	270,948.91	80,106	204,390	5,429	2.00	37.7
	American Falls	50-R1.5	*	(5)	2,846,961.70	1,290,882	1,698,428	56,489	1.98	30.1
	Brownlee	50-R1.5	*	(5)	6,754,737.98	2,954,232	4,138,246	172,643	2.56	24.0
	Bliss	50-R1.5	*	(5)	1,885,123.93	181,345	1,798,035	74,840	3.97	24.0
	Cascade	50-R1.5	*	(5)	2,208,492.78	149,174	2,169,743	64,124	2.90	33.8
	Clear Lake	50-R1.5	*	(5)	96,497.80	91,125	10,197	1,020	1.06	10.0
	Hells Canyon	50-R1.5	*	(5)	3,361,249.91	671,330	2,857,984	120,257	3.58	23.8
	Lower Malad	50-R1.5	*	(5)	351,745.67	87,525	281,806	12,867	3.66	21.9
	Lower Salmon	50-R1.5	*	(5)	1,701,455.57	398,215	1,388,314	59,768	3.51	23.2
	Milner	50-R1.5	*	(5)	2,336,451.70	608,095	1,845,179	47,294	2.02	39.0
	Oxbow	50-R1.5	*	(5)	3,071,574.65	883,426	2,341,727	99,056	3.22	23.6
	Shoshone Falls	50-R1.5	*	(5)	383,367.51	167,847	234,686	11,534	3.01	20.4
	Strike	50-R1.5	*	(5)	2,005,701.48	526,901	1,579,086	71,377	3.56	22.1
	Swan Falls	50-R1.5	*	(5)	3,110,642.15	825,248	2,440,926	85,182	2.74	28.7
	Twin Falls	50-R1.5	*	(5)	538,522.21	45,023	520,424	18,380	3.41	28.3
	Twin Falls (New)	50-R1.5	*	(5)	2,240,671.31	547,716	1,804,987	61,888	2.76	29.2
	Thousand Springs	50-R1.5	*	(5)	752,163.68	466,758	323,013	130,600	17.36	2.5
	Upper Malad	50-R1.5	*	(5)	392,637.15	70,374	341,895	14,721	3.75	23.2
	Upper Salmon A	50-R1.5	*	(5)	1,207,098.47	316,302	951,152	41,434	3.43	23.0
	Upper Salmon B	50-R1.5	*	(5)	1,220,362.84	302,775	978,606	41,566	3.41	23.5
	Total Account 334				*36,775,474.16*	*10,672,827*	*27,941,416*	*1,192,104*	*3.24*	23.4

IDAHO POWER COMPANY
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	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT								
	Hagerman Maintenance Shop	90-R2 *	0	976,871.66	337,013	639,861	30,435	3.12	21.0
	Milner Dam	90-R2 *	0	48,307.16	9,127	39,181	720	1.49	54.4
	Niagara Springs Hatchery	90-R2 *	0	73,522.57	17,040	56,483	2,039	2.77	27.7
	Hells Canyon Maintenance Shop	90-R2 *	0	799,451.96	247,742	551,708	19,941	2.49	27.7
	Rapid River Hatchery	90-R2 *	0	29,848.16	12,905	16,943	621	2.08	27.3
	American Falls	90-R2 *	0	1,805,640.50	449,757	1,355,884	31,261	1.73	43.4
	Brownlee	90-R2 *	0	3,254,248.62	1,616,111	1,638,139	60,553	1.86	27.1
	Bliss	90-R2 *	0	562,062.64	201,451	360,612	14,148	2.52	25.5
	Cascade	90-R2 *	0	1,101,278.52	379,155	722,123	15,056	1.37	48.0
	Clear Lake	90-R2 *	0	22,720.55	6,584	16,136	1,550	6.82	10.4
	Hells Canyon	90-R2 *	0	736,374.99	306,584	429,789	16,159	2.19	26.6
	Lower Malad	90-R2 *	0	82,186.44	55,035	27,150	1,118	1.36	24.3
	Lower Salmon	90-R2 *	0	285,836.81	193,195	92,639	3,723	1.30	24.9
	Milner	90-R2 *	0	649,695.83	153,422	496,272	8,997	1.38	55.2
	Oxbow Hatchery	90-R2 *	0	10,959.41	234	10,725	387	3.53	27.7
	Oxbow	90-R2 *	0	800,618.15	258,834	541,783	20,007	2.50	27.1
	Pahsimerio Accum. Ponds	90-R2 *	0	10,992.98	1,552	9,441	341	3.10	27.7
	Pahsimerio Trapping	90-R2 *	0	13,001.12	324	12,676	467	3.59	27.1
	Shoshone Falls	90-R2 *	0	203,507.40	45,848	157,658	6,676	3.28	23.6
	Strike	90-R2 *	0	651,067.66	209,864	441,203	18,071	2.78	24.4
	Swan Falls	90-R2 *	0	1,420,261.42	339,300	1,080,964	33,598	2.37	32.2
	Twin Falls	90-R2 *	0	99,093.87	53,763	45,332	1,420	1.43	31.9
	Twin Falls (New)	90-R2 *	0	468,032.70	90,717	377,317	11,531	2.46	32.7
	Thousand Springs	90-R2 *	0	56,738.95	56,740	0	0	-	-
	Upper Malad	90-R2 *	0	78,664.05	55,242	23,422	970	1.23	24.2
	Upper Salmon A	90-R2 *	0	107,990.34	77,326	30,664	1,191	1.10	25.8
	Upper Salmon B	90-R2 *	0	180,897.28	89,871	91,027	3,608	1.99	25.2
	Upper Salmon Common	90-R2 *	0	1,930.37	528	1,402	54	2.80	26.0
	Total Account 335			*14,531,802.11*	*5,265,264*	*9,266,534*	*304,642*	*2.10*	30.4
335.10	MISCELLANEOUS POWER PLANT EQUIPMENT - EQUIPMENT	15-SQ	0	41,734.74	29,301	12,434	1,010	2.42	12.3
335.20	MISCELLANEOUS POWER PLANT EQUIPMENT - FURNITURE	20-SQ	0	392,652.62	244,490	148,163	13,876	3.53	10.7
335.30	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTER	5-SQ	0	653,750.14	475,312	178,437	89,248	13.65	2.0
336.00	ROADS, RAILROADS AND BRIDGES								
	Milner Dam	75-R3 *	0	12,737.21	2,530	10,207	194	1.52	52.6
	Niagara Springs Hatchery	75-R3 *	0	46,667.72	46,668	0	0	-	-
	Rapid River Hatchery	75-R3 *	0	7,197.39	7,197	0	0	-	-
	American Falls	75-R3 *	0	306,332.58	118,400	187,932	4,644	1.52	40.5
	Brownlee	75-R3 *	0	518,444.14	253,478	264,966	10,421	2.01	25.4
	Bliss	75-R3 *	0	486,476.64	189,405	297,071	11,585	2.38	25.6
	Cascade	75-R3 *	0	122,668.04	41,700	80,968	1,780	1.45	45.5
	Clear Lake	75-R3 *	0	11,097.30	10,657	440	44	0.40	10.0
	Hells Canyon	75-R3 *	0	819,191.89	494,335	324,857	12,820	1.56	25.3
	Lower Malad	75-R3 *	0	244,565.45	118,578	125,987	5,022	2.05	25.1
	Lower Salmon	75-R3 *	0	88,693.04	47,749	40,944	1,626	1.83	25.2
	Milner	75-R3 *	0	489,139.50	97,083	392,057	7,347	1.50	53.4
	Oxbow Hatchery	75-R3 *	0	3,070.44	3,070	0	0	-	-

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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Oxbow	75-R3	*	0	565,842.36	245,248	320,595	13,235	2.34	24.2
	Pahsimerio Accum. Ponds	75-R3	*	0	26,502.74	21,010	5,493	204	0.77	26.9
	ROADS, RAILROADS AND BRIDGES, cont.									
	Pahsimerio Trapping	75-R3	*	0	15,612.35	15,222	390	14	0.09	27.9
	Shoshone Falls	75-R3	*	0	51,383.40	36,807	14,577	779	1.52	18.7
	Strike	75-R3	*	0	238,870.92	173,076	65,795	3,016	1.26	21.8
	Swan Falls	75-R3	*	0	835,946.15	312,318	523,629	16,617	1.99	31.5
	Twin Falls	75-R3	*	0	893,773.50	314,396	579,377	18,122	2.03	32.0
	Twin Falls (New)	75-R3	*	0	1,023,829.64	211,075	812,755	24,659	2.41	33.0
	Thousand Springs	75-R3	*	0	52,910.46	45,228	7,683	3,106	5.87	2.5
	Upper Malad	75-R3	*	0	60,117.68	30,379	29,739	1,215	2.02	24.5
	Upper Salmon A	75-R3	*	0	1,650.89	661	990	38	2.30	26.1
	Upper Salmon Common	75-R3	*	0	27,708.47	27,708	0	0	-	-
	Total Account 336				*6,950,429.90*	*2,863,978*	*4,086,452*	*136,488*	*1.96*	29.9
	TOTAL HYDRAULIC PRODUCTION PLANT				**625,096,093.97**	**284,481,498**	**433,051,697**	**14,497,089**	***2.32***	
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	Salmon Diesel	Square	*	0	11,959.08	11,959	0	0	-	-
	Evander Andrews	Square	*	0	4,276,832.78	296,054	3,980,779	134,941	3.16	29.5
	Bennett Mountain	Square	*	0	1,012,940.68	50,665	962,276	27,892	2.75	34.5
	Total Account 341				*5,301,732.54*	*358,678*	*4,943,055*	*162,833*	*3.07*	*30.4*
342.00	FUEL HOLDERS									
	Salmon Diesel	Square	*	0	61,306.39	61,306	0	0	-	-
	Evander Andrews	Square	*	0	1,433,423.71	249,652	1,183,772	40,128	2.80	29.5
	Bennett Mountain	Square	*	0	2,025,881.34	101,331	1,924,550	55,784	2.75	34.5
	Total Account 342				*3,520,611.44*	*412,289*	*3,108,322*	*95,912*	*2.72*	*32.4*
343.00	PRIME MOVERS									
	Evander Andrews	Square	*	0	28,676,958.09	1,167,561	27,509,396	932,522	3.25	29.5
	Bennett Mountain	Square	*	0	1,280,075.86	63,332	1,216,744	35,268	2.76	34.5
	Total Account 343				*29,957,033.95*	*1,230,893*	*28,726,140*	*967,790*	*3.23*	*29.7*
344.00	GENERATORS									
	Salmon Diesel	Square	*	0	541,644.95	541,645	0	0	-	-
	Evander Andrews	Square	*	0	13,166,034.86	5,656,938	7,509,097	254,546	1.93	29.5
	Bennett Mountain	Square	*	0	47,977,781.77	(6,601,483)	54,579,265	1,582,007	3.30	34.5
	Total Account 344				*61,685,461.58*	*(402,900)*	*62,088,362*	*1,836,553*	*2.98*	*33.8*
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	Salmon Diesel	Square	*	0	285,139.96	68,989	216,151	216,151	75.81	1.0
	Evander Andrews	Square	*	0	2,877,127.34	267,373	2,609,755	88,467	3.07	29.5

IDAHO POWER COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
Bennett Mountain	Square *	0	1,519,410.98	75,998	1,443,413	41,838	2.75	34.5
Total Account 345			*4,681,678.28*	*412,360*	*4,269,319*	*346,456*	*7.40*	*12.3*

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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Salmon Diesel	Square	*	0	1,004.50	259	746	746	74.27	1.0
	Evander Andrews	Square	*	0	1,380,971.70	354,602	1,026,370	34,792	2.52	29.5
	Bennett Mountain	Square	*	0	4,132.42	129	4,003	116	2.81	34.5
	Total Account 346				*1,386,108.62*	*354,990*	*1,031,119*	*35,654*	*2.57*	*28.9*
	TOTAL OTHER PRODUCTION PLANT				**106,532,626.41**	**2,366,310**	**104,166,317**	**3,445,198**	**3.23**	
	TRANSMISSION PLANT									
350.20	LAND RIGHTS AND EASEMENTS	65-R3		0	22,454,969.55	4,125,397	18,329,572	338,260	1.51	54.2
350.21	RIGHTS OF WAY	65-R3		0	3,837,633.30	171,293	3,666,340	57,533	1.50	63.7
352.00	STRUCTURES AND IMPROVEMENTS	60-R3		(30)	36,779,609.35	18,536,761	29,276,731	618,958	1.68	47.3
353.00	STATION EQUIPMENT	45-R1		(5)	245,790,680.50	78,937,911	179,142,305	5,061,625	2.06	35.4
354.00	TOWERS AND FIXTURES	65-S3		(25)	98,003,480.18	29,046,585	93,457,763	1,924,444	1.96	48.6
355.00	POLES AND FIXTURES	55-R2		(70)	77,282,149.59	43,843,782	87,535,871	2,416,448	3.13	36.2
356.00	OVERHEAD CONDUCTORS AND DEVICES	65-R1.5		(30)	120,017,113.68	44,636,909	111,385,340	2,305,954	1.92	48.3
359.00	ROADS AND TRAILS	65-R3		0	318,351.06	243,747	74,604	3,134	0.98	23.8
	TOTAL TRANSMISSION PLANT				**604,483,987.21**	**219,542,385**	**522,868,526**	**12,726,356**	**2.11**	
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	65-R2.5		(30)	20,494,136.28	6,687,719	19,954,660	379,681	1.85	52.6
362.00	STATION EQUIPMENT	50-R0.5		(5)	142,958,358.69	36,679,371	113,426,903	2,695,793	1.89	42.1
364.00	POLES, TOWERS AND FIXTURES	44-R1.5		(50)	194,701,581.47	89,991,024	202,061,348	6,407,092	3.29	31.5
365.00	OVERHEAD CONDUCTORS AND DEVICES	47-R0.5		(40)	98,919,000.73	36,125,365	102,361,235	2,917,577	2.95	35.1
366.00	UNDERGROUND CONDUIT	60-R2		(20)	43,631,618.27	8,876,804	43,481,140	849,496	1.95	51.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES	50-S0.5		(15)	162,350,092.50	55,349,272	131,353,327	3,199,488	1.97	41.1
368.00	LINE TRANSFORMERS	37-R1		5	318,764,969.11	138,262,721	164,564,000	5,337,672	1.67	30.8
369.00	SERVICES	35-R2.5		(40)	51,272,290.59	31,266,977	40,514,230	1,583,874	3.09	25.6
370.00	METERS	20-O1		0	48,196,011.03	8,475,983	39,720,024	3,350,581	6.95	11.9
370.10	METERS - AMR EQUIPMENT	15-S3		0	4,426,243.43	104,830	4,321,414	299,334	6.76	14.4
371.10	PHOTOVOLTAIC INSTALLATIONS	10-S4		(5)	359,317.71	359,318	17,966	13,219	3.68	1.4
371.20	INSTALLATION ON CUSTOMER PREMISES	15-R2		(5)	2,274,716.24	2,190,308	198,144	14,274	0.63	13.9
373.20	STREET LIGHTING AND SIGNAL SYSTEMS	25-R1.5		(25)	4,067,069.77	2,771,816	2,312,019	166,226	4.09	13.9
	TOTAL DISTRIBUTION PLANT				**1,092,415,405.82**	**417,141,508**	**864,286,410**	**27,214,307**	**2.49**	
	GENERAL PLANT									
390.11	STRUCTURES AND IMPROVEMENTS - CHQ BUILDING	100-S1.5	*	(5)	25,833,040.80	6,460,650	20,664,043	614,746	2.38	33.6
390.12	STRUCTURES AND IMPROVEMENTS - EXCL. CHQ BLDG	50-L2		(5)	31,212,783.91	7,456,277	25,317,150	697,970	2.24	36.3
390.20	LEASEHOLD IMPROVEMENTS	30-S3		0	7,345,253.07	3,413,752	3,931,501	189,347	2.58	20.8
391.10	OFFICE FURNITURE & EQUIPMENT - FURNITURE	20-SQ		0	11,786,383.96	5,748,949	6,037,436	585,505	4.97	10.3
391.20	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	5-SQ		0	22,696,314.19	10,863,401	11,832,913	5,531,614	24.37	2.1
391.21	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	7-L4		0	2,867,432.50	1,301,416	1,566,016	400,302	13.96	3.9

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
392.10	TRANSPORTATION EQUIPMENT - AUTOMOBILES	10-L2.5	25	322,580.19	124,143	117,792	20,109	6.23	5.9
392.30	TRANSPORTATION EQUIPMENT - AIRCRAFT	8-S2.5	50	2,580,219.74	333,471	956,640	222,334	8.62	4.3

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
392.40	TRANSPORTATION EQUIPMENT - SMALL TRUCKS	10-L2.5	25	17,830,083.75	8,707,876	4,664,689	638,683	3.58	7.3
392.50	TRANSPORTATION EQUIPMENT - MISC.	10-L2.5	25	523,039.68	325,373	66,909	7,816	1.49	8.6
392.60	TRANSPORTATION EQUIPMENT - LARGE TRUCKS (HYD)	19-S2	25	22,447,727.51	6,899,432	9,936,364	829,351	3.69	12.0
392.70	TRANSPORTATION EQUIP. - LARGE TRUCKS (NON-HYD)	19-S2	25	3,795,829.55	1,764,183	1,082,690	90,686	2.39	11.9
392.90	TRANSPORTATION EQUIPMENT - TRAILERS	30-S1.5	25	3,551,268.75	1,166,923	1,496,527	70,776	1.99	21.1
393.00	STORES EQUIPMENT	25-SQ	0	982,360.91	467,709	514,653	53,001	5.40	9.7
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	20-SQ	0	4,222,287.57	1,826,861	2,395,426	204,375	4.84	11.7
395.00	LABORATORY EQUIPMENT	20-SQ	0	9,761,135.63	4,419,489	5,341,646	526,113	5.39	10.2
396.00	POWER OPERATED EQUIPMENT	16-S0	30	7,306,984.97	1,580,752	3,534,141	507,497	6.95	7.0
397.10	COMMUNICATION EQUIPMENT - TELEPHONES	15-SQ	0	6,914,005.40	3,654,968	3,259,038	425,792	6.16	7.7
397.20	COMMUNICATION EQUIPMENT - MICROWAVES	15-SQ	0	17,233,659.37	5,709,382	11,524,279	1,204,847	6.99	9.6
397.30	COMMUNICATION EQUIPMENT - RADIO	15-SQ	0	2,623,458.46	1,176,789	1,446,672	219,374	8.36	6.6
397.40	COMMUNICATION EQUIPMENT - FIBER OPTIC	10-SQ	0	1,425,704.34	776,047	649,657	116,956	8.20	5.6
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	0	2,910,349.72	979,897	1,930,454	278,626	9.57	6.9
	TOTAL GENERAL PLANT			**206,171,903.97**	**75,157,740**	**118,266,636**	**13,435,820**	**6.52**	
	TOTAL DEPRECIABLE PLANT			**3,467,925,738.92**	**1,513,314,851**	**2,404,767,382**	**89,258,469**	**2.57**	
	NONDEPRECIABLE PLANT								
310.10	LAND			1,167,304.15					
330.00	LAND			22,523,450.15					
340.00	LAND			402,745.39					
350.00	LAND			2,460,259.88					
360.00	LAND			4,607,314.94					
389.00	LAND			8,760,764.66					
	TOTAL NONDEPRECIABLE PLANT			**39,921,839.17**					
	TOTAL ELECTRIC PLANT			**3,507,847,578.09**	**1,513,314,851**	**2,404,767,382**	**89,258,469**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE. ACTUAL LIFE SPAN FOR EACH FACILITY IS SHOW BEGINNING ON PAGE II-27 OF THIS REPORT.

ATTACHMENT 2

DEPRECIATION PROCEDURES
EQUAL LIFE GROUP (ELG) vs. AVERAGE SYSTEM LIFE (ASL)

	Investment (*)	Depr Life (Years)
ELG		
Asset #1	$5,000	5
Asset #2	$5,000	25
	$10,000	
ASL		
Total Weighted Assets	**$10,000**	15

* Assumes no salvage value or removal costs.

	ELG Procedure				ASL Procedure		ASL Variance
	Depr 5-Yr Prop	Depr 25-Yr Prop	Annual Expense	Accum Depr	Depr 15-Yr Prop	Accum Depr	
Yr 1	1,000	200	1,200	1,200	667	667	(533)
Yr 2	1,000	200	1,200	2,400	667	1,333	(533)
Yr 3	1,000	200	1,200	3,600	667	2,000	(533)
Yr 4	1,000	200	1,200	4,800	667	2,667	(533)
Yr 5	1,000	200	1,200	6,000	667	3,333	(533)
Yr 6		200	200	6,200	667	4,000	467
Yr 7		200	200	6,400	667	4,667	467
Yr 8		200	200	6,600	667	5,333	467
Yr 9		200	200	6,800	667	6,000	467
Yr 10		200	200	7,000	667	6,667	467
Yr 11		200	200	7,200	667	7,333	467
Yr 12		200	200	7,400	667	8,000	467
Yr 13		200	200	7,600	667	8,667	467
Yr 14		200	200	7,800	667	9,333	467
Yr 15		200	200	8,000	667	10,000	467
Yr 16		200	200	8,200			(200)
Yr 17		200	200	8,400			(200)
Yr 18		200	200	8,600			(200)
Yr 19		200	200	8,800			(200)
Yr 20		200	200	9,000			(200)
Yr 21		200	200	9,200			(200)
Yr 22		200	200	9,400			(200)
Yr 23		200	200	9,600			(200)
Yr 24		200	200	9,800			(200)
Yr 25		200	200	10,000			(200)
Total	5,000	5,000	**10,000**		**10,000**		(0)

ATTACHMENT NO. 6

Settlement Stipulation
(IPUC Case No. IPC-E-08-06)

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ORDER AUTHORIZING A CHANGE IN DEPRECIATION RATES APPLICABLE TO ELECTRIC PROPERTY	CASE NO. IPC-E-08-06 STIPULATION

This Stipulation is entered into among Idaho Power Company ("Idaho Power" or "Company") and the Staff of the Idaho Public Utilities Commission ("Staff") as their signatures appear at the end of this Stipulation. Idaho Power and Staff are hereinafter together referred to as the "Parties."

The purpose of this Stipulation is to settle all of the issues in the above-referenced proceeding.

I. APPLICATION AND PROCEDURAL HISTORY

On April 1, 2008, Idaho Power filed an Application with the Idaho Public Utilities Commission ("IPUC" or the "Commission") requesting authority to institute revised depreciation rates for the Company's electric plant in service ("Application"). No major changes have been made to the Company's depreciation rates in the last five years.

The Company's depreciation rates last changed in December 2003 when the Commission issued Order No. 29363 in Case No. IPC-E-03-07. In its April 1, 2008, filing, the Company sought an accounting order approving revised depreciation rates that the Company would prospectively apply to its depreciable plant in service. The Company did not request to change its electric rates with the Application.

The proposed depreciation rates included in the Company's Application were based upon the results of a detailed depreciation study of the Company's electric plant in service as of December 31, 2006. On the basis of $3,467,925,739 of depreciable plant in service on December 31, 2006, and using the average service life procedure, Idaho Power requested depreciation changes in its Application that would have decreased the Company's total annual depreciation expense by $6,713,451.

Of particular note, the Company's Application proposed depreciation rates that differed from those authorized in Order No. 29363 are as follows:

1. <u>Extension of Steam Plant Useful Lives</u>

    - Extended useful lives of steam plant consistent with those of the managing partners of the Company's steam power plants.

2. <u>Changes in Removal Costs of Steam Plant</u>

    - *Account 311 – Structures and Improvements*: The net salvage percentage at Bridger changed from (5) to (10). This was based on the historical data and the Company's depreciation study consultant's professional judgment.

- *Account 312 – Boiler Plant Equipment (other than Bridger)*: The net salvage percentage changed from (10) to (5) because historical data did not support the previous net salvage percentage.

- *Account 314 – Turbogenerator Units (other than Bridger)*: The net salvage percentage changed from (10) to (5) because historical data did not support the previous net salvage percentage.

- *Account 315 – Accessory Electric Equipment*: The net salvage percentage remains at 0.

- *Account 316 – Miscellaneous Power Plant Equipment*: The net salvage percentage at Bridger changed from 0 to (5) based on the Company's depreciation study consultant's professional judgment.

3. <u>Addition of Bennett Mountain Plant</u>

- This gas-fired generation plant was added to the Company's generation portfolio in March 2005. Because the plant's design and function are similar to the existing Danskin plant, the service life for Bennett Mountain is the same as for Danskin.

4. <u>Automated Meter Reading ("AMR") Assets</u>

- *Meters (Account 370)*: AMR meters have a different expected service life from other metering assets. Therefore, it is separately identified and segregated into subaccount 370.10.

- *Other AMR Assets (Communications equipment, etc.)*: Other AMR assets have been booked into the appropriate classification of plant accounts/subaccounts. Because the AMR assets have a similar service life to other assets in those accounts, AMR assets do not require segregation into a separate subaccount with a unique service life.

- Whether or not an AMR asset has been given a separately identified subaccount, a unique "unit of property number" has been established for all AMI equipment so it can be queried if specific identification or reporting is required.

5. <u>Account 335 – Miscellaneous Hydro Power Plant Equipment (Subaccounts for Computers, Equipment, and Furniture)</u>

- All assets at the Company's hydro plants, regardless of their function, continue to be segregated from the rest of the Company's plant investments. However, investments in furniture, computers, etc., do not have the long service life of most hydro assets. Therefore, those types of assets were segregated into separate subaccounts which more accurately reflect the presumed service life of the asset.

Following the Commission's April 17, 2008, Notice of Application and Intervention Deadline (Order No. 30532), no petitions to intervene were filed. Analysis by the Staff evaluated Idaho Power's proposed depreciation rates with those used in the industry by similar companies. After a series of settlement discussions, on August 27, 2008, the Parties agreed to several adjustments to the Company's proposed depreciation expenses for certain accounts associated with steam production plant (Bridger), hydraulic production plant (Thousand Springs and Clear Lake), other production plant (Salmon diesel generator), and transmission poles and fixtures. The Parties accepted the depreciation accruals originally proposed by the Company in its Application for its other plant categories.

The changes agreed to by the Parties increased the overall reduction in the requested depreciation expense from about $89.3 million to $87.5 million. The Parties' settlement of this matter is embodied in this Stipulation.

More specifically, the Parties agree as follows:

II. AGREEMENT

1. To settle the depreciation matter identified above, the Parties agree to revise Idaho Power's requested decrease in depreciation expense from $6,713,451 to

$8,514,422 based upon year 2006 plant levels and agree to the following adjustments to the Company's Application request:

a. Increase the service life of Jim Bridger steam plant in Accounts 311-316 from 52 years to 54 years and change the net salvage from (10) to (7).

b. Increase the life span of Thousand Springs hydraulic production plant in Accounts 331-336 from 2009 to 2014.

c. Increase the life span of Clear Lake hydraulic production plant in Accounts 331-336 from 2017 to 2020.

d. Increase the life span of Salmon diesel generator in Accounts 341-346 from 2007 to 2017.

e. Change the net salvage of Account 355 poles and fixtures from (70) to (60).

2. The Parties agree to the depreciation accruals originally proposed by the Company in its Application for its other plant categories.

3. The Parties agree to undertake a detailed review of the accrual rates for the following plant assets when the Company files its next depreciation study:

a. Bridger Assets (Accounts 311-316)

b. Bennett Mountain (Accounts 341-346)

c. Clear Lake hydraulic production plant (Accounts 331-336)

d. Meters (Account 370)

e. Computers (Account 391.2)

f. Corporate Aircraft (Account 392.3)

4. The Parties agree that the depreciation rates agreed to herein, and further described in Attachment No. 1, shall become effective on August 1, 2008.

5. Attachment No. 2 details the Company's current accrual rates, filed accrual rates, and stipulated accrual rates.

6. The Parties agree that this Stipulation is in the public interest with respect to the issues covered by it and that all of the terms of the Stipulation are fair, just, and reasonable.

7. This Stipulation will be entered into the record as evidence in this proceeding. The Parties shall support adoption of the Stipulation and acceptance of the Stipulation as a reasonable resolution to the issues identified previously. If the Idaho Public Utilities Commission rejects all or any part of this Stipulation, any Party disadvantaged by such action, including Idaho Power, shall have the right, upon written notice to the Commission and all Parties to the proceeding, within seven (7) days of the Commission's Order, to withdraw from the Stipulation. No withdrawing Party shall be bound by the terms of this Stipulation and any withdrawing Party may seek reconsideration of the Commission's Order. Withdrawal from the Stipulation would not prevent the withdrawing Party from subsequently requesting that the Commission hold a hearing in this case to resolve the depreciation matters identified above.

8. The Parties have negotiated this Stipulation as an integrated settlement document. The Parties recommend that the Commission accept this Stipulation without material change or condition.

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

9-5-08 Date	Lisa D. Nordstrom LISA D. NORDSTROM Attorney for Idaho Power Company
9-5-08 Date	WELDON B. STUTZMAN Attorney for Idaho Public Utilities Commission

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-08-06

IDAHO POWER COMPANY

ATTACHMENT NO. 1

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT									
	STEAM PRODUCTION PLANT									
310.20	LAND AND WATER RIGHTS	75-R4	*	0	203,015.26	133,168	69,847	3,209	1.58	21.8
311.00	STRUCTURES AND IMPROVEMENTS									
	Boardman	100-S1	*	(10)	13,664,764.34	10,401,832	4,629,409	204,502	1.50	22.6
	Jim Bridger	100-S1	*	(7)	63,198,974.93	46,843,278	20,779,625	957,574	1.52	21.7
	Valmy Unit 1	100-S1	*	(10)	29,417,622.31	21,939,527	10,419,858	442,158	1.50	23.6
	Valmy Unit 2	100-S1	*	(10)	24,255,332.32	15,671,964	11,008,903	402,266	1.66	27.4
	Total Account 311				*130,536,693.90*	*94,856,601*	*46,837,795*	*2,006,500*	*1.54*	*23.3*
312.10	BOILER PLANT EQUIPMENT - SCRUBBERS									
	Jim Bridger	60-R3	*	(7)	58,908,365.65	41,166,395	21,865,558	1,018,118	1.73	21.5
	Valmy Unit 2	60-R3	*	(5)	20,941,250.57	13,659,862	8,328,451	316,666	1.51	26.3
	Total Account 312.1				*79,849,616.22*	*54,826,257*	*30,194,009*	*1,334,784*	*1.67*	*22.6*
312.20	BOILER PLANT EQUIPMENT - OTHER									
	Boardman	70-R1.5	*	(5)	35,288,034.40	24,991,899	12,060,537	547,888	1.55	22.0
	Jim Bridger	70-R1.5	*	(7)	229,201,271.84	121,268,927	123,976,435	5,829,371	2.54	21.3
	Valmy Unit 1	70-R1.5	*	(5)	76,723,967.25	48,681,408	31,878,757	1,391,327	1.81	22.9
	Valmy Unit 2	70-R1.5	*	(5)	80,418,334.11	49,735,349	34,703,902	1,325,456	1.65	26.2
	Total Account 312.2				*421,631,607.60*	*244,677,583*	*202,619,631*	*9,094,042*	*2.16*	*22.3*
312.30	BOILER PLANT EQUIPMENT - RAILCARS									
	Boardman	25-R3		20	1,498,563.91	592,002	606,849	44,194	2.95	13.7
	Jim Bridger	25-R3		20	2,478,477.91	1,350,060	632,722	57,260	2.31	11.1
	Total Account 312.3				*3,977,041.82*	*1,942,062*	*1,239,571*	*101,454*	*2.55*	*12.2*
314.00	TURBOGENERATOR UNITS									
	Boardman	50-S0.5	*	(5)	12,082,591.21	6,914,586	5,772,136	282,044	2.33	20.5
	Jim Bridger	50-S0.5	*	(7)	68,938,574.30	32,920,951	40,843,324	2,061,912	2.99	19.8
	Valmy Unit 1	50-S0.5	*	(5)	17,109,524.14	11,887,785	6,077,214	301,882	1.76	20.1
	Valmy Unit 2	50-S0.5	*	(5)	24,455,252.30	15,405,938	10,272,077	449,977	1.84	22.8
	Total Account 314				*122,585,941.95*	*67,129,260*	*62,964,751*	*3,095,815*	*2.53*	*20.3*
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	Boardman	65-S1.5	*	0	4,099,075.54	3,187,420	911,655	42,951	1.05	21.2
	Jim Bridger	65-S1.5	*	(7)	25,368,186.72	20,271,169	6,872,790	342,507	1.35	20.1
	Valmy Unit 1	65-S1.5	*	0	15,908,284.23	11,276,003	4,632,281	208,945	1.31	22.2
	Valmy Unit 2	65-S1.5	*	0	15,983,662.93	10,012,750	5,970,914	232,254	1.45	25.7
	Total Account 315				*61,359,209.42*	*44,747,342*	*18,387,640*	*826,657*	*1.35*	*22.2*

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Boardman	50-R0.5	*	(5)	1,695,292.87	839,166	940,893	45,979	2.71	20.5
	Jim Bridger	50-R0.5	*	(7)	4,859,302.37	3,107,280	2,092,174	105,818	2.18	19.8
	Valmy Unit 1	50-R0.5	*	(5)	3,066,769.39	1,784,820	1,435,289	68,204	2.22	21.0
	Valmy Unit 2	50-R0.5	*	(5)	1,686,053.18	905,737	864,619	36,244	2.15	23.9
	Total Account 316				*11,307,417.81*	*6,637,003*	*5,332,975*	*256,245*	*2.27*	*20.8*
316.10	MISCELLANEOUS POWER PLANT EQUIPMENT - AUTOMOBILES	10-L2.5		25	58,859.95	1,746	42,399	5,601	9.52	7.6
316.40	MISCELLANEOUS POWER PLANT EQUIPMENT - SMALL TRUCKS									
	Jim Bridger	10-L2.5		25	208,142.12	180,864	(24,757)	0	-	-
	Valmy Unit 1	10-L2.5		25	18,003.44	15,151	(1,648)	0	-	-
	Total Account 316.4				*226,145.56*	*196,015*	*(26,405)*	*0*	-	-
316.50	MISCELLANEOUS POWER PLANT EQUIPMENT - MISCELLANEOUS									
	Boardman	10-L2.5		25	41,585.39	6,149	25,040	2,900	6.97	8.6
	Jim Bridger	10-L2.5		25	23,360.90	10,238	7,283	958	4.10	7.6
	Valmy Unit 1	10-L2.5		25	59,433.94	16,251	28,324	3,529	5.94	8.0
	Total Account 316.5				*124,380.23*	*32,638*	*60,647*	*7,387*	*5.94*	*8.2*
316.70	MISCELLANEOUS POWER PLANT EQUIP.-LARGE TRUCKS	19-S2		25	251,360.52	25,575	162,945	9,760	3.88	16.7
316.80	MISCELLANEOUS POWER PLANT EQUIP.-POWER OPERATED EQ	16-S0		30	1,114,431.30	(579,840)	1,359,943	145,714	13.08	9.3
	TOTAL STEAM PRODUCTION PLANT				833,225,721.54	514,625,410	369,245,748	16,887,168	2.03	
	HYDRAULIC PRODUCTION PLANT									
331.00	STRUCTURES AND IMPROVEMENTS									
	Hagerman Maintenance Shop	100-R2.5	*	(25)	1,558,200.45	588,724	1,359,027	64,117	4.11	21.2
	Milner Dam	100-R2.5	*	(25)	814,224.25	230,854	786,926	13,990	1.72	56.3
	Niagara Springs Hatchery	100-R2.5	*	(25)	5,029,555.80	1,275,880	5,011,064	179,766	3.57	27.9
	Hells Canyon Maintenance Shop	100-R2.5	*	(25)	1,604,833.95	566,934	1,439,107	51,501	3.21	27.9
	Rapid River Hatchery	100-R2.5	*	(25)	2,402,683.49	928,540	2,074,814	74,310	3.09	27.9
	American Falls	100-R2.5	*	(25)	11,857,401.29	6,038,675	8,783,073	197,107	1.66	44.6
	Brownlee	100-R2.5	*	(25)	30,068,208.63	17,491,534	20,093,727	726,270	2.42	27.7
	Bliss	100-R2.5	*	(25)	666,848.63	400,703	432,861	17,049	2.56	25.4
	Cascade	100-R2.5	*	(25)	7,364,153.73	3,051,973	6,153,221	123,336	1.67	49.9
	Clear Lake	100-R2.5	*	(25)	193,278.70	178,418	63,181	4,730	2.45	13.4
	Hells Canyon	100-R2.5	*	(25)	2,403,495.64	894,612	2,109,757	76,124	3.17	27.7
	Lower Malad	100-R2.5	*	(25)	600,746.78	373,630	377,303	15,214	2.53	24.8
	Lower Salmon	100-R2.5	*	(25)	888,303.03	527,177	583,200	22,849	2.57	25.5
	Milner	100-R2.5	*	(25)	9,512,589.19	2,729,102	9,161,634	159,676	1.68	57.4
	Oxbow Hatchery	100-R2.5	*	(25)	1,472,035.50	726,845	1,113,198	40,052	2.72	27.8
	Oxbow	100-R2.5	*	(25)	9,830,938.42	4,836,770	7,451,902	273,365	2.78	27.3
	Oxbow Common	100-R2.5	*	(25)	111,952.27	111,952	27,988	1,038	0.93	27.0
	Pahsimerio Accum. Ponds	100-R2.5	*	(25)	4,187,993.72	299,623	4,935,370	175,424	4.19	28.1
	Pahsimerio Trapping	100-R2.5	*	(25)	935,129.61	547,693	621,219	22,406	2.40	27.7
	Shoshone Falls	100-R2.5	*	(25)	1,139,956.09	668,822	756,120	32,266	2.83	23.4

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	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	STRUCTURES AND IMPROVEMENTS, cont.									
	Strike	100-R2.5	*	(25)	2,789,968.67	1,649,271	1,838,190	76,335	2.74	24.1
	Swan Falls	100-R2.5	*	(25)	25,223,735.85	6,914,133	24,615,536	753,550	2.99	32.7
	Twin Falls	100-R2.5	*	(25)	661,285.30	316,699	509,908	15,857	2.40	32.2
	Twin Falls (New)	100-R2.5	*	(25)	10,146,761.46	2,678,549	10,004,903	301,443	2.97	33.2
	Thousand Springs	100-R2.5	*	(25)	327,624.51	327,625	81,903	11,021	3.36	7.4
	Upper Malad	100-R2.5	*	(25)	357,819.86	274,952	172,323	7,041	1.97	24.5
	Upper Salmon A	100-R2.5	*	(25)	859,310.39	566,928	507,208	20,532	2.39	24.7
	Upper Salmon B	100-R2.5	*	(25)	326,935.58	151,070	257,600	10,033	3.07	25.7
	Upper Salmon Common	100-R2.5	*	(25)	352,331.39	153,746	286,668	11,100	3.15	25.8
	Total Account 331				*133,688,302.18*	*55,501,434*	*111,608,931*	*3,477,502*	*2.60*	*32.1*
332.10	RESERVOIRS, DAMS AND WATERWAYS - RELOCATION									
	Brownlee	90-S4	*	(20)	8,639,663.66	4,592,743	5,774,853	212,233	2.46	27.2
	Hells Canyon	90-S4	*	(20)	940,788.93	462,648	666,299	24,487	2.60	27.2
	Oxbow	90-S4	*	(20)	56,309.00	29,019	38,552	1,417	2.52	27.2
	Oxbow Common	90-S4	*	(20)	1,927,919.83	1,224,350	1,089,153	39,664	2.06	27.5
	Brownlee Common	90-S4	*	(20)	7,895,824.78	5,019,821	4,455,169	163,733	2.07	27.2
	Total Account 332.1				*19,460,506.20*	*11,328,581*	*12,024,026*	*441,534*	*2.27*	*27.2*
332.20	RESERVOIRS, DAMS AND WATERWAYS									
	Milner Dam	90-S4	*	(20)	614,874.97	172,994	564,856	9,559	1.55	59.1
	American Falls	90-S4	*	(20)	4,242,904.39	2,438,545	2,652,940	57,114	1.35	46.5
	Brownlee	90-S4	*	(20)	52,631,542.49	31,583,559	31,574,292	1,143,926	2.17	27.6
	Bliss	90-S4	*	(20)	7,480,783.71	5,874,296	3,102,646	131,012	1.75	23.7
	Cascade	90-S4	*	(20)	3,145,630.46	1,335,517	2,439,240	46,756	1.49	52.2
	Clear Lake	90-S4	*	(20)	584,984.73	450,439	251,543	18,715	3.20	13.4
	Hells Canyon	90-S4	*	(20)	51,724,316.81	25,151,853	36,917,327	1,316,438	2.55	28.0
	Lower Malad	90-S4	*	(20)	2,078,537.32	1,484,241	1,010,005	41,380	1.99	24.4
	Lower Salmon	90-S4	*	(20)	6,602,823.37	4,705,338	3,218,051	134,181	2.03	24.0
	Milner	90-S4	*	(20)	16,532,174.93	4,635,107	15,203,504	252,333	1.53	60.3
	Oxbow	90-S4	*	(20)	30,319,404.87	16,297,679	20,085,606	731,526	2.41	27.5
	Oxbow Common	90-S4	*	(20)	9,871.65	4,162	7,684	269	2.72	28.6
	Shoshone Falls	90-S4	*	(20)	512,401.48	478,649	136,233	8,809	1.72	15.5
	Strike	90-S4	*	(20)	9,764,915.58	7,374,540	4,343,360	187,848	1.92	23.1
	Swan Falls	90-S4	*	(20)	13,641,458.81	5,426,542	10,943,208	329,280	2.41	33.2
	Twin Falls	90-S4	*	(20)	263,089.08	203,663	112,044	4,996	1.90	22.4
	Twin Falls (New)	90-S4	*	(20)	7,669,627.33	1,604,132	7,599,420	223,512	2.91	34.0
	Thousand Springs	90-S4	*	(20)	2,083,442.82	2,083,443	416,690	55,559	2.67	7.5
	Upper Malad	90-S4	*	(20)	1,292,528.44	1,009,149	541,886	23,284	1.80	23.3
	Upper Salmon A	90-S4	*	(20)	1,153,590.73	342,659	1,041,650	42,594	3.69	24.5
	Upper Salmon B	90-S4	*	(20)	2,758,487.94	1,945,794	1,364,392	56,122	2.03	24.3
	Upper Salmon Common	90-S4	*	(20)	730,039.01	462,019	414,028	17,944	2.46	23.1
	Hells Canyon Common	90-S4	*	(20)	3,723,168.70	2,606,285	1,861,518	65,487	1.76	28.4
	Total Account 332.2				*219,560,599.62*	*117,670,605*	*145,802,123*	*4,898,644*	*2.23*	*29.8*
332.30	RESERVOIRS, DAMS AND WATERWAYS - NEZ PERCE	Square	*	0	5,599,934.61	1,006,639	4,593,296	160,717	2.87	28.6

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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	Milner Dam	80-R3	*	(5)	878,005.87	210,871	711,035	13,153	1.50	54.1
	American Falls	80-R3	*	(5)	26,401,757.45	12,972,335	14,749,510	351,166	1.33	42.0
	Brownlee	80-R3	*	(5)	41,621,633.25	24,952,949	18,749,765	692,584	1.66	27.1
	Bliss	80-R3	*	(5)	4,367,360.46	2,949,965	1,635,762	69,661	1.60	23.5
	Cascade	80-R3	*	(5)	9,087,779.30	3,388,774	6,153,395	130,379	1.43	47.2
	Clear Lake	80-R3	*	(5)	742,499.27	82,179	697,446	51,982	7.00	13.4
	Hells Canyon	80-R3	*	(5)	10,936,002.51	3,941,566	7,541,238	284,219	2.60	26.5
	Lower Malad	80-R3	*	(5)	528,365.79	390,110	164,673	7,357	1.39	22.4
	Lower Salmon	80-R3	*	(5)	4,472,826.76	3,222,402	1,474,065	63,203	1.41	23.3
	Milner	80-R3	*	(5)	23,352,421.08	5,440,945	19,079,097	347,172	1.49	55.0
	Oxbow	80-R3	*	(5)	10,849,416.56	5,703,638	5,688,249	219,701	2.03	25.9
	Shoshone Falls	80-R3	*	(5)	1,624,269.34	749,464	956,018	41,504	2.56	23.0
	Strike	80-R3	*	(5)	4,674,860.58	3,215,915	1,692,689	74,596	1.60	22.7
	Swan Falls	80-R3	*	(5)	25,775,660.82	6,244,039	20,820,406	638,355	2.48	32.6
	Twin Falls	80-R3	*	(5)	1,430,443.99	257,847	1,244,119	38,915	2.72	32.0
	Twin Falls (New)	80-R3	*	(5)	15,678,462.57	3,498,786	12,963,600	391,295	2.50	33.1
	Thousand Springs	80-R3	*	(5)	729,122.94	521,519	244,062	32,696	4.48	7.5
	Upper Malad	80-R3	*	(5)	476,485.37	333,132	167,178	7,249	1.52	23.1
	Upper Salmon A	80-R3	*	(5)	1,191,919.73	607,043	644,472	26,398	2.21	24.4
	Upper Salmon B	80-R3	*	(5)	2,621,614.05	739,588	2,013,106	78,786	3.01	25.6
	Total Account 333				*187,440,907.69*	*79,423,067*	*117,389,885*	*3,560,371*	*1.90*	33.0
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	Hagerman Maintenance Shop	50-R1.5	*	(5)	39,066.76	8,428	32,592	1,635	4.19	19.9
	Milner Dam	50-R1.5	*	(5)	270,948.91	80,106	204,390	5,429	2.00	37.7
	American Falls	50-R1.5	*	(5)	2,846,961.70	1,290,882	1,698,428	56,489	1.98	30.1
	Brownlee	50-R1.5	*	(5)	6,754,737.98	2,954,232	4,138,246	172,643	2.56	24.0
	Bliss	50-R1.5	*	(5)	1,885,123.93	181,345	1,798,035	74,840	3.97	24.0
	Cascade	50-R1.5	*	(5)	2,208,492.78	149,174	2,169,743	64,124	2.90	33.8
	Clear Lake	50-R1.5	*	(5)	96,497.80	91,125	10,197	807	0.84	12.6
	Hells Canyon	50-R1.5	*	(5)	3,361,249.91	671,330	2,857,984	120,257	3.58	23.8
	Lower Malad	50-R1.5	*	(5)	351,745.67	87,525	281,806	12,867	3.66	21.9
	Lower Salmon	50-R1.5	*	(5)	1,701,455.57	398,215	1,388,314	59,768	3.51	23.2
	Milner	50-R1.5	*	(5)	2,336,451.70	608,095	1,845,179	47,294	2.02	39.0
	Oxbow	50-R1.5	*	(5)	3,071,574.65	883,426	2,341,727	99,056	3.22	23.6
	Shoshone Falls	50-R1.5	*	(5)	383,367.51	167,847	234,686	11,534	3.01	20.4
	Strike	50-R1.5	*	(5)	2,005,701.48	526,901	1,579,086	71,377	3.56	22.1
	Swan Falls	50-R1.5	*	(5)	3,110,642.15	825,248	2,440,926	85,182	2.74	28.7
	Twin Falls	50-R1.5	*	(5)	538,522.21	45,023	520,424	18,380	3.41	28.3
	Twin Falls (New)	50-R1.5	*	(5)	2,240,671.31	547,716	1,804,987	61,888	2.76	29.2
	Thousand Springs	50-R1.5	*	(5)	752,163.68	466,758	323,013	44,135	5.87	7.3
	Upper Malad	50-R1.5	*	(5)	392,637.15	70,374	341,895	14,721	3.75	23.2
	Upper Salmon A	50-R1.5	*	(5)	1,207,098.47	316,302	951,152	41,434	3.43	23.0
	Upper Salmon B	50-R1.5	*	(5)	1,220,362.84	302,775	978,606	41,566	3.41	23.5
	Total Account 334				*36,775,474.16*	*10,672,827*	*27,941,416*	*1,105,426*	*3.01*	25.3

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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Hagerman Maintenance Shop	90-R2	*	0	976,871.66	337,013	639,861	30,435	3.12	21.0
	Milner Dam	90-R2	*	0	48,307.16	9,127	39,181	720	1.49	54.4
	Niagara Springs Hatchery	90-R2	*	0	73,522.57	17,040	56,483	2,039	2.77	27.7
	Hells Canyon Maintenance Shop	90-R2	*	0	799,451.96	247,742	551,708	19,941	2.49	27.7
	Rapid River Hatchery	90-R2	*	0	29,848.16	12,905	16,943	621	2.08	27.3
	American Falls	90-R2	*	0	1,805,640.50	449,757	1,355,884	31,261	1.73	43.4
	Brownlee	90-R2	*	0	3,254,248.62	1,616,111	1,638,139	60,553	1.86	27.1
	Bliss	90-R2	*	0	562,062.64	201,451	360,612	14,148	2.52	25.5
	Cascade	90-R2	*	0	1,101,278.52	379,155	722,123	15,056	1.37	48.0
	Clear Lake	90-R2	*	0	22,720.55	6,584	16,136	1,210	5.33	13.3
	Hells Canyon	90-R2	*	0	736,374.99	306,584	429,789	16,159	2.19	26.6
	Lower Malad	90-R2	*	0	82,186.44	55,035	27,150	1,118	1.36	24.3
	Lower Salmon	90-R2	*	0	285,836.81	193,195	92,639	3,723	1.30	24.9
	Milner	90-R2	*	0	649,695.83	153,422	496,272	8,997	1.38	55.2
	Oxbow Hatchery	90-R2	*	0	10,959.41	234	10,725	387	3.53	27.7
	Oxbow	90-R2	*	0	800,618.15	258,834	541,783	20,007	2.50	27.1
	Pahsimerio Accum. Ponds	90-R2	*	0	10,992.98	1,552	9,441	341	3.10	27.7
	Pahsimerio Trapping	90-R2	*	0	13,001.12	324	12,676	467	3.59	27.1
	Shoshone Falls	90-R2	*	0	203,507.40	45,848	157,658	6,676	3.28	23.6
	Strike	90-R2	*	0	651,067.66	209,864	441,203	18,071	2.78	24.4
	Swan Falls	90-R2	*	0	1,420,261.42	339,300	1,080,964	33,598	2.37	32.2
	Twin Falls	90-R2	*	0	99,093.87	53,763	45,332	1,420	1.43	31.9
	Twin Falls (New)	90-R2	*	0	468,032.70	90,717	377,317	11,531	2.46	32.7
	Thousand Springs	90-R2	*	0	56,738.95	56,740	0	0	-	-
	Upper Malad	90-R2	*	0	78,664.05	55,242	23,422	970	1.23	24.2
	Upper Salmon A	90-R2	*	0	107,990.34	77,326	30,664	1,191	1.10	25.8
	Upper Salmon B	90-R2	*	0	180,897.28	89,871	91,027	3,608	1.99	25.2
	Upper Salmon Common	90-R2	*	0	1,930.37	528	1,402	54	2.80	26.0
	Total Account 335				*14,531,802.11*	*5,265,264*	*9,266,534*	*304,302*	*2.09*	30.5
335.10	MISCELLANEOUS POWER PLANT EQUIPMENT - EQUIPMENT	15-SQ		0	41,734.74	29,301	12,434	1,010	2.42	12.3
335.20	MISCELLANEOUS POWER PLANT EQUIPMENT - FURNITURE	20-SQ		0	392,652.62	244,490	148,163	13,876	3.53	10.7
335.30	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTER	5-SQ		0	653,750.14	475,312	178,437	89,248	13.65	2.0
336.00	ROADS, RAILROADS AND BRIDGES									
	Milner Dam	75-R3	*	0	12,737.21	2,530	10,207	194	1.52	52.6
	Niagara Springs Hatchery	75-R3	*	0	46,667.72	46,668	0	0	-	-
	Rapid River Hatchery	75-R3	*	0	7,197.39	7,197	0	0	-	-
	American Falls	75-R3	*	0	306,332.58	118,400	187,932	4,644	1.52	40.5
	Brownlee	75-R3	*	0	518,444.14	253,478	264,966	10,421	2.01	25.4
	Bliss	75-R3	*	0	486,476.64	189,405	297,071	11,585	2.38	25.6
	Cascade	75-R3	*	0	122,668.04	41,700	80,968	1,780	1.45	45.5
	Clear Lake	75-R3	*	0	11,097.30	10,657	440	35	0.32	12.6
	Hells Canyon	75-R3	*	0	819,191.89	494,335	324,857	12,820	1.56	25.3
	Lower Malad	75-R3	*	0	244,565.45	118,578	125,987	5,022	2.05	25.1
	Lower Salmon	75-R3	*	0	88,693.04	47,749	40,944	1,626	1.83	25.2
	Milner	75-R3	*	0	489,139.50	97,083	392,057	7,347	1.50	53.4
	Oxbow Hatchery	75-R3	*	0	3,070.44	3,070	0	0	-	-
	Oxbow	75-R3	*	0	565,842.36	245,248	320,595	13,235	2.34	24.2
	Pahsimerio Accum. Ponds	75-R3	*	0	26,502.74	21,010	5,493	204	0.77	26.9

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	ROADS, RAILROADS AND BRIDGES, cont.									
	Pahsimerio Trapping	75-R3	*	0	15,612.35	15,222	390	14	0.09	27.9
	Shoshone Falls	75-R3	*	0	51,383.40	36,807	14,577	779	1.52	18.7
	Strike	75-R3	*	0	238,870.92	173,076	65,795	3,016	1.26	21.8
	Swan Falls	75-R3	*	0	835,946.15	312,318	523,629	16,617	1.99	31.5
	Twin Falls	75-R3	*	0	893,773.50	314,396	579,377	18,122	2.03	32.0
	Twin Falls (New)	75-R3	*	0	1,023,829.64	211,075	812,755	24,659	2.41	33.0
	Thousand Springs	75-R3	*	0	52,910.46	45,228	7,683	1,029	1.94	7.5
	Upper Malad	75-R3	*	0	60,117.68	30,379	29,739	1,215	2.02	24.5
	Upper Salmon A	75-R3	*	0	1,650.89	661	990	38	2.30	26.1
	Upper Salmon Common	75-R3	*	0	27,708.47	27,708	0	0	-	-
	Total Account 336				*6,950,429.90*	*2,863,978*	*4,086,452*	*134,402*	*1.93*	30.4
	TOTAL HYDRAULIC PRODUCTION PLANT				625,096,093.97	284,481,498	433,051,697	14,187,032	2.27	
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	Salmon Diesel	Square	*	0	11,959.08	11,959	0	0	-	-
	Evander Andrews	Square	*	0	4,276,832.78	296,054	3,980,779	134,941	3.16	29.5
	Bennett Mountain	Square	*	0	1,012,940.68	50,665	962,276	27,892	2.75	34.5
	Total Account 341				*5,301,732.54*	*358,678*	*4,943,055*	*162,833*	*3.07*	*30.4*
342.00	FUEL HOLDERS									
	Salmon Diesel	Square	*	0	61,306.39	61,306	0	0	-	-
	Evander Andrews	Square	*	0	1,433,423.71	249,652	1,183,772	40,128	2.80	29.5
	Bennett Mountain	Square	*	0	2,025,881.34	101,331	1,924,550	55,784	2.75	34.5
	Total Account 342				*3,520,611.44*	*412,289*	*3,108,322*	*95,912*	2.72	*32.4*
343.00	PRIME MOVERS									
	Evander Andrews	Square	*	0	28,676,958.09	1,167,561	27,509,396	932,522	3.25	29.5
	Bennett Mountain	Square	*	0	1,280,075.86	63,332	1,216,744	35,268	2.76	34.5
	Total Account 343				*29,957,033.95*	*1,230,893*	*28,726,140*	*967,790*	3.23	*29.7*
344.00	GENERATORS									
	Salmon Diesel	Square	*	0	541,644.95	541,645	0	0	-	-
	Evander Andrews	Square	*	0	13,166,034.86	5,656,938	7,509,097	254,546	1.93	29.5
	Bennett Mountain	Square	*	0	47,977,781.77	(6,601,483)	54,579,265	1,582,007	3.30	34.5
	Total Account 344				*61,685,461.58*	*(402,900)*	*62,088,362*	*1,836,553*	*2.98*	*33.8*
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	Salmon Diesel	Square	*	0	285,139.96	68,989	216,151	20,586	7.22	10.5
	Evander Andrews	Square	*	0	2,877,127.34	267,373	2,609,755	88,467	3.07	29.5
	Bennett Mountain	Square	*	0	1,519,410.98	75,998	1,443,413	41,838	2.75	34.5
	Total Account 345				*4,681,678.28*	*412,360*	*4,269,319*	*150,891*	3.22	*28.3*

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Salmon Diesel	Square	*	0	1,004.50	259	746	72	7.17	10.4
	Evander Andrews	Square	*	0	1,380,971.70	354,602	1,026,370	34,792	2.52	29.5
	Bennett Mountain	Square	*	0	4,132.42	129	4,003	116	2.81	34.5
	Total Account 346				*1,386,108.62*	*354,990*	*1,031,119*	*34,980*	2.52	*29.5*
	TOTAL OTHER PRODUCTION PLANT				**106,532,626.41**	**2,366,310**	**104,166,317**	**3,248,959**	***3.05***	
	TRANSMISSION PLANT									
350.20	LAND RIGHTS AND EASEMENTS	65-R3		0	22,454,969.55	4,125,397	18,329,572	338,260	1.51	54.2
350.21	RIGHTS OF WAY	65-R3		0	3,837,633.30	171,293	3,666,340	57,533	1.50	63.7
352.00	STRUCTURES AND IMPROVEMENTS	60-R3		(30)	36,779,609.35	18,536,761	29,276,731	618,958	1.68	47.3
353.00	STATION EQUIPMENT	45-R1		(5)	245,790,680.50	78,937,911	179,142,305	5,061,625	2.06	35.4
354.00	TOWERS AND FIXTURES	65-S3		(25)	98,003,480.18	29,046,585	93,457,763	1,924,444	1.96	48.6
355.00	POLES AND FIXTURES	55-R2		(60)	77,282,149.59	43,843,782	79,807,657	2,174,304	2.81	36.7
356.00	OVERHEAD CONDUCTORS AND DEVICES	65-R1.5		(30)	120,017,113.68	44,636,909	111,385,340	2,305,954	1.92	48.3
359.00	ROADS AND TRAILS	65-R3		0	318,351.06	243,747	74,604	3,134	0.98	23.8
	TOTAL TRANSMISSION PLANT				**604,483,987.21**	**219,542,385**	**515,140,312**	**12,484,212**	**2.07**	
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	65-R2.5		(30)	20,494,136.28	6,687,719	19,954,660	379,681	1.85	52.6
362.00	STATION EQUIPMENT	50-R0.5		(5)	142,958,358.69	36,679,371	113,426,903	2,695,793	1.89	42.1
364.00	POLES, TOWERS AND FIXTURES	44-R1.5		(50)	194,701,581.47	89,991,024	202,061,348	6,407,092	3.29	31.5
365.00	OVERHEAD CONDUCTORS AND DEVICES	47-R0.5		(40)	98,919,000.73	36,125,365	102,361,235	2,917,577	2.95	35.1
366.00	UNDERGROUND CONDUIT	60-R2		(20)	43,631,618.27	8,876,804	43,481,140	849,496	1.95	51.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES	50-S0.5		(15)	162,350,092.50	55,349,272	131,353,327	3,199,488	1.97	41.1
368.00	LINE TRANSFORMERS	37-R1		5	318,764,969.11	138,262,721	164,564,000	5,337,672	1.67	30.8
369.00	SERVICES	35-R2.5		(40)	51,272,290.59	31,266,977	40,514,230	1,583,874	3.09	25.6
370.00	METERS	20-O1		0	48,196,011.03	8,475,983	39,720,024	3,350,581	6.95	11.9
370.10	METERS - AMR EQUIPMENT	15-S3		0	4,426,243.43	104,830	4,321,414	299,334	6.76	14.4
371.10	PHOTOVOLTAIC INSTALLATIONS	10-S4		(5)	359,317.71	359,318	17,966	13,219	3.68	1.4
371.20	INSTALLATION ON CUSTOMER PREMISES	15-R2		(5)	2,274,716.24	2,190,308	198,144	14,274	0.63	13.9
373.20	STREET LIGHTING AND SIGNAL SYSTEMS	25-R1.5		(25)	4,067,069.77	2,771,816	2,312,019	166,226	4.09	13.9
	TOTAL DISTRIBUTION PLANT				**1,092,415,405.82**	**417,141,508**	**864,286,410**	**27,214,307**	**2.49**	
	GENERAL PLANT									
390.11	STRUCTURES AND IMPROVEMENTS - CHQ BUILDING	100-S1.5	*	(5)	25,833,040.80	6,460,650	20,664,043	614,746	2.38	33.6
390.12	STRUCTURES AND IMPROVEMENTS - EXCL. CHQ BLDG	50-L2		(5)	31,212,783.91	7,456,277	25,317,150	697,970	2.24	36.3
390.20	LEASEHOLD IMPROVEMENTS	30-S3		0	7,345,253.07	3,413,752	3,931,501	189,347	2.58	20.8
391.10	OFFICE FURNITURE & EQUIPMENT - FURNITURE	20-SQ		0	11,786,383.96	5,748,949	6,037,436	585,505	4.97	10.3
391.20	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	5-SQ		0	22,696,314.19	10,863,401	11,832,913	5,531,614	24.37	2.1
391.21	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	7-L4		0	2,867,432.50	1,301,416	1,566,016	400,302	13.96	3.9
392.10	TRANSPORTATION EQUIPMENT - AUTOMOBILES	10-L2.5		25	322,580.19	124,143	117,792	20,109	6.23	5.9
392.30	TRANSPORTATION EQUIPMENT - AIRCRAFT	8-S2.5		50	2,580,219.74	333,471	956,640	222,334	8.62	4.3

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
392.40	TRANSPORTATION EQUIPMENT - SMALL TRUCKS	10-L2.5	25	17,830,083.75	8,707,876	4,664,689	638,683	3.58	7.3
392.50	TRANSPORTATION EQUIPMENT - MISC.	10-L2.5	25	523,039.68	325,373	66,909	7,816	1.49	8.6
392.60	TRANSPORTATION EQUIPMENT - LARGE TRUCKS (HYD)	19-S2	25	22,447,727.51	6,899,432	9,936,364	829,351	3.69	12.0
392.70	TRANSPORTATION EQUIP. - LARGE TRUCKS (NON-HYD)	19-S2	25	3,795,829.55	1,764,183	1,082,690	90,686	2.39	11.9
392.90	TRANSPORTATION EQUIPMENT - TRAILERS	30-S1.5	25	3,551,268.75	1,166,923	1,496,527	70,776	1.99	21.1
393.00	STORES EQUIPMENT	25-SQ	0	982,360.91	467,709	514,653	53,001	5.40	9.7
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	20-SQ	0	4,222,287.57	1,826,861	2,395,426	204,375	4.84	11.7
395.00	LABORATORY EQUIPMENT	20-SQ	0	9,761,135.63	4,419,489	5,341,646	526,113	5.39	10.2
396.00	POWER OPERATED EQUIPMENT	16-S0	30	7,306,984.97	1,580,752	3,534,141	507,497	6.95	7.0
397.10	COMMUNICATION EQUIPMENT - TELEPHONES	15-SQ	0	6,914,005.40	3,654,968	3,259,038	425,792	6.16	7.7
397.20	COMMUNICATION EQUIPMENT - MICROWAVES	15-SQ	0	17,233,659.37	5,709,382	11,524,279	1,204,847	6.99	9.6
397.30	COMMUNICATION EQUIPMENT - RADIO	15-SQ	0	2,623,458.46	1,176,789	1,446,672	219,374	8.36	6.6
397.40	COMMUNICATION EQUIPMENT - FIBER OPTIC	10-SQ	0	1,425,704.34	776,047	649,657	116,956	8.20	5.6
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	0	2,910,349.72	979,897	1,930,454	278,626	9.57	6.9
	TOTAL GENERAL PLANT			206,171,903.97	75,157,740	118,266,636	13,435,820	6.52	
	TOTAL DEPRECIABLE PLANT			3,467,925,738.92	1,513,314,851	2,404,157,120	87,457,498	2.52	
	NONDEPRECIABLE PLANT								
310.10	LAND			1,167,304.15					
330.00	LAND			22,523,450.15					
340.00	LAND			402,745.39					
350.00	LAND			2,460,259.88					
360.00	LAND			4,607,314.94					
389.00	LAND			8,760,764.66					
	TOTAL NONDEPRECIABLE PLANT			39,921,839.17					
	TOTAL ELECTRIC PLANT			3,507,847,578.09	1,513,314,851	2,404,157,120	87,457,498		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE. ACTUAL LIFE SPAN FOR EACH FACILITY IS SHOW BEGINNING ON PAGE II-27 OF THIS REPORT.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-08-06

IDAHO POWER COMPANY

ATTACHMENT NO. 2

IDAHO POWER COMPANY
COMPARISON OF CURRENT, FILED AND SETTLEMENT ACCRUAL RATES AND AMOUNTS

	ACCOUNT (1)	CURRENT ACCRUAL RATE	ACCRUAL AMOUNT	AS FILED ACCRUAL RATE	ACCRUAL AMOUNT	SETTLEMENT ACCRUAL RATE	ACCRUAL AMOUNT
	ELECTRIC PLANT						
	STEAM PRODUCTION PLANT						
310.20	LAND AND WATER RIGHTS	2.27	4,608	1.81	3,674	1.58	3,209
311.00	STRUCTURES AND IMPROVEMENTS						
	Boardman	2.62	358,017	1.50	204,502	1.50	204,502
	Jim Bridger	2.17	1,371,418	1.90	1,198,753	1.52	957,574
	Valmy Unit 1	3.12	917,830	1.50	442,158	1.50	442,158
	Valmy Unit 2	3.00	727,660	1.66	402,266	1.66	402,266
			3,374,925		*2,247,679*		*2,006,500*
312.10	BOILER PLANT EQUIPMENT - SCRUBBERS						
	Jim Bridger	2.72	1,602,308	1.87	1,100,601	1.73	1,018,118
	Valmy Unit 2	2.88	603,108	1.51	316,666	1.51	316,666
			2,205,416		*1,417,267*		*1,334,784*
312.20	BOILER PLANT EQUIPMENT - OTHER						
	Boardman	2.96	1,044,526	1.55	547,888	1.55	547,888
	Jim Bridger	2.59	5,936,313	2.80	6,418,641	2.54	5,829,371
	Valmy Unit 1	3.41	2,616,287	1.81	1,391,327	1.81	1,391,327
	Valmy Unit 2	3.21	2,581,429	1.65	1,325,456	1.65	1,325,456
			12,178,555		*9,683,312*		*9,094,042*
312.30	BOILER PLANT EQUIPMENT - RAILCARS						
	Boardman	3.04	45,556	2.95	44,194	2.95	44,194
	Jim Bridger	2.61	64,688	2.31	57,260	2.31	57,260
			110,244		*101,454*		*101,454*
314.00	TURBOGENERATOR UNITS						
	Boardman	2.80	338,313	2.33	282,044	2.33	282,044
	Jim Bridger	3.50	2,412,850	3.26	2,248,580	2.99	2,061,912
	Valmy Unit 1	3.75	641,607	1.76	301,882	1.76	301,882
	Valmy Unit 2	3.51	858,379	1.84	449,977	1.84	449,977
			4,251,149		*3,282,483*		*3,095,815*
315.00	ACCESSORY ELECTRIC EQUIPMENT						
	Boardman	1.97	80,752	1.05	42,951	1.05	42,951
	Jim Bridger	1.61	408,428	1.13	286,647	1.35	342,507
	Valmy Unit 1	2.61	415,206	1.31	208,945	1.31	208,945
	Valmy Unit 2	2.61	417,174	1.45	232,254	1.45	232,254
			1,321,560		*770,797*		*826,657*
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT						
	Boardman	3.30	55,945	2.71	45,979	2.71	45,979
	Jim Bridger	2.47	120,025	2.35	114,144	2.18	105,818
	Valmy Unit 1	3.75	115,004	2.22	68,204	2.22	68,204
	Valmy Unit 2	3.56	60,023	2.15	36,244	2.15	36,244
			350,997		*264,571*		*256,245*
316.10	MISCELLANEOUS POWER PLANT EQUIPMENT - AUTOMOBILES	1.78	1,048	9.52	5,601	9.52	5,601
316.40	MISCELLANEOUS POWER PLANT EQUIPMENT - SMALL TRUCKS						
	Jim Bridger	1.17	2,435	-			
	Valmy Unit 1	5.74	1,033	-			
	Total Account 316.4		*3,468*	-			
316.50	MISCELLANEOUS POWER PLANT EQUIPMENT - MISCELLANEOUS						
	Boardman	9.45	3,930	6.97	2,900	6.97	2,900
	Jim Bridger	9.45	1,019	4.10	958	4.10	958
	Valmy Unit 1	4.36	0	5.94	3,529	5.94	3,529
			4,949		*7,387*		*7,387*
316.70	MISCELLANEOUS POWER PLANT EQUIPMENT - LARGE TRUCKS	3.45	8,672	3.88	9,760	3.88	9,760

IDAHO POWER COMPANY
COMPARISON OF CURRENT, FILED AND SETTLEMENT ACCRUAL RATES AND AMOUNTS

	ACCOUNT (1)	CURRENT ACCRUAL RATE	ACCRUAL AMOUNT	AS FILED ACCRUAL RATE	ACCRUAL AMOUNT	SETTLEMENT ACCRUAL RATE	ACCRUAL AMOUNT
316.80	MISCELLANEOUS POWER PLANT EQUIPMENT - POWER OPERA	4.31	48,032	13.08	145,714	13.08	145,714
	TOTAL STEAM PRODUCTION PLANT		23,863,623		17,939,699		16,887,168
	HYDRAULIC PRODUCTION PLANT						
331.00	STRUCTURES AND IMPROVEMENTS						
	Hagerman Maintenance Shop	3.33	51,888	4.11	64,117	4.11	64,117
	Milner Dam	1.70	13,842	1.72	13,990	1.72	13,990
	Niagara Springs Hatchery	3.21	161,449	3.57	179,766	3.57	179,766
	Hells Canyon Maintenance Shop	2.85	45,738	3.21	51,501	3.21	51,501
	Rapid River Hatchery	1.94	46,612	3.09	74,310	3.09	74,310
	American Falls	1.62	192,090	1.66	197,107	1.66	197,107
	Brownlee	2.26	679,542	2.42	726,270	2.42	726,270
	Bliss	2.23	14,871	2.56	17,049	2.56	17,049
	Cascade	1.65	121,509	1.67	123,336	1.67	123,336
	Clear Lake	2.49	4,813	3.14	6,072	2.45	4,730
	Hells Canyon	2.65	63,693	3.17	76,124	3.17	76,124
	Lower Malad	2.36	14,178	2.53	15,214	2.53	15,214
	Lower Salmon	2.26	20,076	2.57	22,849	2.57	22,849
	Milner	1.66	157,909	1.68	159,676	1.68	159,676
	Oxbow Hatchery	2.39	35,182	2.72	40,052	2.72	40,052
	Oxbow	2.64	259,537	2.78	273,365	2.78	273,365
	Oxbow Common	0.65	728	0.93	1,038	0.93	1,038
	Pahsimerio Accum. Ponds	2.42	101,349	4.19	175,424	4.19	175,424
	Pahsimerio Trapping	2.09	19,544	2.40	22,406	2.40	22,406
	Shoshone Falls	2.66	30,323	2.83	32,266	2.83	32,266
	Strike	2.49	69,470	2.74	76,335	2.74	76,335
	Swan Falls	2.81	708,787	2.99	753,550	2.99	753,550
	Twin Falls	2.20	14,548	2.40	15,857	2.40	15,857
	Twin Falls (New)	2.81	285,124	2.97	301,443	2.97	301,443
	Thousand Springs	5.47	17,921	10.04	32,909	3.36	11,021
	Upper Malad	1.79	6,405	1.97	7,041	1.97	7,041
	Upper Salmon A	2.25	19,334	2.39	20,532	2.39	20,532
	Upper Salmon B	2.17	7,095	3.07	10,033	3.07	10,033
	Upper Salmon Common	2.83	9,971	3.15	11,100	3.15	11,100
			3,173,528		3,500,732		3,477,502
332.10	RESERVOIRS, DAMS AND WATERWAYS - RELOCATION						
	Brownlee	2.12	183,161	2.46	212,233	2.46	212,233
	Hells Canyon	2.27	21,356	2.60	24,487	2.60	24,487
	Oxbow	2.18	1,228	2.52	1,417	2.52	1,417
	Oxbow Common	1.72	33,160	2.06	39,664	2.06	39,664
	Brownlee Common	1.74	137,387	2.07	163,733	2.07	163,733
			376,292		441,534		441,534
332.20	RESERVOIRS, DAMS AND WATERWAYS						
	Milner Dam	1.43	8,793	1.55	9,559	1.55	9,559
	American Falls	1.19	50,491	1.35	57,114	1.35	57,114
	Brownlee	1.88	989,473	2.17	1,143,926	2.17	1,143,926
	Bliss	1.48	110,716	1.75	131,012	1.75	131,012
	Cascade	1.34	42,151	1.49	46,756	1.49	46,756
	Clear Lake	3.21	18,778	4.14	24,200	3.20	18,715
	Hells Canyon	2.25	1,163,797	2.55	1,316,438	2.55	1,316,438
	Lower Malad	1.69	35,127	1.99	41,380	1.99	41,380
	Lower Salmon	1.70	112,248	2.03	134,181	2.03	134,181
	Milner	1.41	233,104	1.53	252,333	1.53	252,333
	Oxbow	2.12	642,771	2.41	731,526	2.41	731,526
	Oxbow Common	2.36	233	2.72	269	2.72	269
	Shoshone Falls	1.40	7,174	1.72	8,809	1.72	8,809
	Strike	1.63	159,168	1.92	187,848	1.92	187,848
	Swan Falls	2.11	287,835	2.41	329,280	2.41	329,280
	Twin Falls	1.76	4,630	1.90	4,996	1.90	4,996
	Twin Falls (New)	2.60	199,410	2.91	223,512	2.91	223,512
	Thousand Springs	3.17	66,045	8.04	167,517	2.67	55,559
	Upper Malad	1.52	19,646	1.80	23,284	1.80	23,284
	Upper Salmon A	1.59	18,342	3.69	42,594	3.69	42,594
	Upper Salmon B	1.45	39,998	2.03	56,122	2.03	56,122
	Upper Salmon Common	1.80	13,141	2.46	17,944	2.46	17,944
	Hells Canyon Common	1.39	51,752	1.76	65,487	1.76	65,487

IDAHO POWER COMPANY
COMPARISON OF CURRENT, FILED AND SETTLEMENT ACCRUAL RATES AND AMOUNTS

	ACCOUNT (1)	CURRENT ACCRUAL RATE	ACCRUAL AMOUNT	AS FILED ACCRUAL RATE	ACCRUAL AMOUNT	SETTLEMENT ACCRUAL RATE	ACCRUAL AMOUNT
			4,274,823		5,016,087		4,898,644
332.30	RESERVOIRS, DAMS AND WATERWAYS -NEZ PERCE	1.44	80,639	2.87	160,717	2.87	160,717
333.00	WATER WHEELS, TURBINES AND GENERATORS						
	Milner Dam	1.51	13,258	1.50	13,153	1.50	13,153
	American Falls	1.33	351,143	1.33	351,166	1.33	351,166
	Brownlee	1.57	653,460	1.66	692,584	1.66	692,584
	Bliss	1.62	70,751	1.60	69,661	1.60	69,661
	Cascade	1.44	130,864	1.43	130,379	1.43	130,379
	Clear Lake	1.82	13,513	8.99	66,717	7.00	51,982
	Hells Canyon	2.40	262,464	2.60	284,219	2.60	284,219
	Lower Malad	1.40	7,397	1.39	7,357	1.39	7,357
	Lower Salmon	1.38	61,725	1.41	63,203	1.41	63,203
	Milner	1.50	350,286	1.49	347,172	1.49	347,172
	Oxbow	2.02	219,158	2.03	219,701	2.03	219,701
	Shoshone Falls	2.58	41,906	2.56	41,504	2.56	41,504
	Strike	1.61	75,265	1.60	74,596	1.60	74,596
	Swan Falls	2.44	628,926	2.48	638,355	2.48	638,355
	Twin Falls	2.37	33,902	2.72	38,915	2.72	38,915
	Twin Falls (New)	2.46	385,690	2.50	391,295	2.50	391,295
	Thousand Springs	9.00	65,621	13.47	98,241	4.48	32,696
	Upper Malad	1.54	7,338	1.52	7,249	1.52	7,249
	Upper Salmon A	1.91	22,766	2.21	26,398	2.21	26,398
	Upper Salmon B	1.03	27,003	3.01	78,786	3.01	78,786
			3,422,436		3,640,651		3,560,371
334.00	ACCESSORY ELECTRIC EQUIPMENT						
	Hagerman Maintenance Shop	3.89	1,520	4.19	1,635	4.19	1,635
	Milner Dam	2.07	5,609	2.00	5,429	2.00	5,429
	American Falls	2.00	56,939	1.98	56,489	1.98	56,489
	Brownlee	2.33	157,385	2.56	172,643	2.56	172,643
	Bliss	3.74	70,504	3.97	74,840	3.97	74,840
	Cascade	2.44	53,887	2.90	64,124	2.90	64,124
	Clear Lake	0.70	675	1.06	1,020	0.84	807
	Hells Canyon	3.42	114,955	3.58	120,257	3.58	120,257
	Lower Malad	3.56	12,522	3.66	12,867	3.66	12,867
	Lower Salmon	3.41	58,020	3.51	59,768	3.51	59,768
	Milner	2.06	48,131	2.02	47,294	2.02	47,294
	Oxbow	3.11	95,526	3.22	99,056	3.22	99,056
	Shoshone Falls	1.97	7,552	3.01	11,534	3.01	11,534
	Strike	3.26	65,386	3.56	71,377	3.56	71,377
	Swan Falls	2.64	82,121	2.74	85,182	2.74	85,182
	Twin Falls	3.19	17,179	3.41	18,380	3.41	18,380
	Twin Falls (New)	2.66	59,602	2.76	61,888	2.76	61,888
	Thousand Springs	7.26	54,607	17.36	130,600	5.87	44,135
	Upper Malad	2.98	11,701	3.75	14,721	3.75	14,721
	Upper Salmon A	3.33	40,196	3.43	41,434	3.43	41,434
	Upper Salmon B	3.18	38,808	3.41	41,566	3.41	41,566
			1,052,825		1,192,104		1,105,426
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT						
	Hagerman Maintenance Shop	3.02	29,502	3.12	30,435	3.12	30,435
	Milner Dam	1.56	754	1.49	720	1.49	720
	Niagara Springs Hatchery	2.26	1,662	2.77	2,039	2.77	2,039
	Hells Canyon Maintenance Shop	2.46	19,667	2.49	19,941	2.49	19,941
	Rapid River Hatchery	2.28	681	2.08	621	2.08	621
	American Falls	1.50	27,085	1.73	31,261	1.73	31,261
	Brownlee	1.28	41,654	1.86	60,553	1.86	60,553
	Bliss	1.40	7,869	2.52	14,148	2.52	14,148
	Cascade	1.41	15,528	1.37	15,056	1.37	15,056
	Clear Lake	5.67	1,288	6.82	1,550	5.33	1,210
	Hells Canyon	2.30	16,937	2.19	16,159	2.19	16,159
	Lower Malad	1.18	970	1.36	1,118	1.36	1,118
	Lower Salmon	1.31	3,744	1.30	3,723	1.30	3,723
	Milner	1.46	9,486	1.38	8,997	1.38	8,997
	Oxbow Hatchery	3.55	389	3.53	387	3.53	387
	Oxbow	2.40	19,215	2.50	20,007	2.50	20,007
	Pahsimerio Accum. Ponds	2.94	323	3.10	341	3.10	341
	Pahsimerio Trapping	3.50	455	3.59	467	3.59	467
	Shoshone Falls	2.28	4,640	3.28	6,676	3.28	6,676
	Strike	1.60	10,417	2.78	18,071	2.78	18,071

IDAHO POWER COMPANY
COMPARISON OF CURRENT, FILED AND SETTLEMENT ACCRUAL RATES AND AMOUNTS

	ACCOUNT (1)	CURRENT ACCRUAL RATE	ACCRUAL AMOUNT	AS FILED ACCRUAL RATE	ACCRUAL AMOUNT	SETTLEMENT ACCRUAL RATE	ACCRUAL AMOUNT
	Swan Falls	2.41	34,228	2.37	33,598	2.37	33,598
	Twin Falls	1.59	1,576	1.43	1,420	1.43	1,420
	Twin Falls (New)	2.42	11,326	2.46	11,531	2.46	11,531
	Thousand Springs	2.65	1,504	-		-	
	Upper Malad	1.43	1,125	1.23	970	1.23	970
	Upper Salmon A	0.78	842	1.10	1,191	1.10	1,191
	Upper Salmon B	1.89	3,419	1.99	3,608	1.99	3,608
	Upper Salmon Common	2.60	50	2.80	54	2.80	54
			266,336		304,642		304,302
335.10	MISCELLANEOUS POWER PLANT EQUIPMENT - EQUIPMENT			2.42	1,010	2.42	1,010
335.20	MISCELLANEOUS POWER PLANT EQUIPMENT - FURNITURE			3.53	13,876	3.53	13,876
335.30	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTER			13.65	89,248	13.65	89,248
336.00	ROADS, RAILROADS AND BRIDGES						
	Milner Dam	1.53	195	1.52	194	1.52	194
	Niagara Springs Hatchery	0.00	0	0.00		0.00	
	Rapid River Hatchery	0.00	0	0.00		0.00	
	American Falls	1.52	4,656	1.52	4,644	1.52	4,644
	Brownlee	2.03	10,524	2.01	10,421	2.01	10,421
	Bliss	2.40	11,675	2.38	11,585	2.38	11,585
	Cascade	1.45	1,779	1.45	1,780	1.45	1,780
	Clear Lake	0.48	53	0.40	44	0.32	35
	Hells Canyon	1.58	12,943	1.56	12,820	1.56	12,820
	Lower Malad	2.08	5,087	2.05	5,022	2.05	5,022
	Lower Salmon	1.89	1,676	1.83	1,626	1.83	1,626
	Milner	1.51	7,386	1.50	7,347	1.50	7,347
	Oxbow Hatchery	0.00	0	0.00		0.00	
	Oxbow	2.25	12,731	2.34	13,235	2.34	13,235
	Pahsimerio Accum. Ponds	0.77	204	0.77	204	0.77	204
	Pahsimerio Trapping	0.09	14	0.09	14	0.09	14
	Shoshone Falls	1.65	848	1.52	779	1.52	779
	Strike	1.07	2,556	1.26	3,016	1.26	3,016
	Swan Falls	1.96	16,385	1.99	16,617	1.99	16,617
	Twin Falls	2.03	18,144	2.03	18,122	2.03	18,122
	Twin Falls (New)	2.37	24,265	2.41	24,659	2.41	24,659
	Thousand Springs	4.87	2,577	5.87	3,106	1.94	1,029
	Upper Malad	2.03	1,220	2.02	1,215	2.02	1,215
	Upper Salmon A	2.36	39	2.30	38	2.30	38
	Upper Salmon Common	0.01	3	-		-	
			134,960		136,488		134,402
	TOTAL HYDRAULIC PRODUCTION PLANT		12,781,839		14,497,089		14,187,032
	OTHER PRODUCTION PLANT						
341.00	STRUCTURES AND IMPROVEMENTS						
	Salmon Diesel	8.43	1,008	-			
	Evander Andrews - Units 2 & 3	2.88	123,173	3.16	134,941	3.16	134,941
	Evander Andrews - Unit 1	2.88				2.88	
	Bennett Mountain	2.88	29,173	2.75	27,892	2.75	27,892
			153,354		162,833		162,833
342.00	FUEL HOLDERS						
	Salmon Diesel	1.62	993	-			
	Evander Andrews - Units 2 & 3	2.88	41,283	2.80	40,128	2.80	40,128
	Evander Andrews - Unit 1	2.88				2.88	
	Bennett Mountain	2.88	58,345	2.75	55,784	2.75	55,784
			100,621		*95,912*		*95,912*
343.00	PRIME MOVERS						
	Evander Andrews - Units 2 & 3	2.88	825,896	3.25	932,522	3.25	932,522
	Evander Andrews - Unit 1	2.88				2.88	
	Bennett Mountain	2.88	36,866	2.76	35,268	2.76	35,268
			862,762		967,790		967,790
344.00	GENERATORS						
	Salmon Diesel	1.78	9,641	-			

IDAHO POWER COMPANY
COMPARISON OF CURRENT, FILED AND SETTLEMENT ACCRUAL RATES AND AMOUNTS

	ACCOUNT (1)	CURRENT ACCRUAL RATE	ACCRUAL AMOUNT	AS FILED ACCRUAL RATE	ACCRUAL AMOUNT	SETTLEMENT ACCRUAL RATE	ACCRUAL AMOUNT
	Evander Andrews - Units 2 & 3	2.88	379,182	1.93	254,546	1.93	254,546
	Evander Andrews - Unit 1	2.88				2.88	
	Bennett Mountain	2.88	1,381,760	3.30	1,582,007	3.30	1,582,007
			1,770,583		*1,836,553*		*1,836,553*
345.00	ACCESSORY ELECTRIC EQUIPMENT						
	Salmon Diesel	4.10	11,691	75.81	216,151	7.22	20,586
	Evander Andrews - Units 2 & 3	2.88	82,861	3.07	88,467	3.07	88,467
	Evander Andrews - Unit 1	2.88				2.88	
	Bennett Mountain	2.88	43,759	2.75	41,838	2.75	41,838
			138,311		*346,456*		*150,891*
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT						
	Salmon Diesel	0.00	0	74.27	746	7.17	72
	Evander Andrews - Units 2 & 3	2.88	39,772	2.52	34,792	2.52	34,792
	Evander Andrews - Unit 1	2.88				2.88	
	Bennett Mountain	2.88	119	2.81	116	2.81	116
			39,891		*35,654*		*34,980*
	TOTAL OTHER PRODUCTION PLANT		3,065,522		3,445,198		3,248,959
	TRANSMISSION PLANT						
350.20	LAND RIGHTS AND EASEMENTS	1.54	345,807	1.51	338,260	1.51	338,260
350.21	RIGHTS OF WAY	4.09	0	1.50	57,533	1.50	57,533
352.00	STRUCTURES AND IMPROVEMENTS	1.29	474,457	1.68	618,958	1.68	618,958
353.00	STATION EQUIPMENT	2.12	5,210,762	2.06	5,061,625	2.06	5,061,625
354.00	TOWERS AND FIXTURES	2.45	2,401,085	1.96	1,924,444	1.96	1,924,444
355.00	POLES AND FIXTURES	2.04	2,272,095	3.13	2,416,448	2.81	2,174,304
356.00	OVERHEAD CONDUCTORS AND DEVICES	1.96	2,352,335	1.92	2,305,954	1.92	2,305,954
359.00	ROADS AND TRAILS	1.07	3,406	0.98	3,134	0.98	3,134
	TOTAL TRANSMISSION PLANT		13,059,947		12,726,356		12,484,212
	DISTRIBUTION PLANT						
361.00	STRUCTURES AND IMPROVEMENTS	2.05	420,130	1.85	379,681	1.85	379,681
362.00	STATION EQUIPMENT	1.64	2,344,517	1.89	2,695,793	1.89	2,695,793
364.00	POLES, TOWERS AND FIXTURES	3.67	7,145,548	3.29	6,407,092	3.29	6,407,092
365.00	OVERHEAD CONDUCTORS AND DEVICES	3.25	3,214,868	2.95	2,917,577	2.95	2,917,577
366.00	UNDERGROUND CONDUIT	2.04	890,085	1.95	849,496	1.95	849,496
367.00	UNDERGROUND CONDUCTORS AND DEVICES	2.73	4,432,158	1.97	3,199,488	1.97	3,199,488
368.00	LINE TRANSFORMERS	1.73	5,514,634	1.67	5,337,672	1.67	5,337,672
369.00	SERVICES	3.69	1,891,947	3.09	1,583,874	3.09	1,583,874
370.00	METERS	4.06	1,956,758	6.95	3,350,581	6.95	3,350,581
370.10	METERS - AMR EQUIPMENT	4.06	179,705	6.76	299,334	6.76	299,334
371.10	PHOTOVOLTAIC INSTALLATIONS	28.42	102,118	3.68	13,219	3.68	13,219
371.20	INSTALLATION ON CUSTOMER PREMISES	11.85	269,554	0.63	14,274	0.63	14,274
373.20	STREET LIGHTING AND SIGNAL SYSTEMS	5.75	233,857	4.09	166,226	4.09	166,226
	TOTAL DISTRIBUTION PLANT		28,595,879		27,214,307		27,214,307
	GENERAL PLANT						
390.11	STRUCTURES AND IMPROVEMENTS - CHQ BUILDING	2.27	586,410	2.38	614,746	2.38	614,746
390.12	STRUCTURES AND IMPROVEMENTS - EXCL. CHQ BLDG	2.17	677,317	2.24	697,970	2.24	697,970
390.20	LEASEHOLD IMPROVEMENTS	3.85	282,792	2.58	189,347	2.58	189,347
391.10	OFFICE FURNITURE & EQUIPMENT - FURNITURE	9.66	1,138,565	4.97	585,505	4.97	585,505
391.20	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	20.00	4,539,263	24.37	5,531,614	24.37	5,531,614
391.21	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	16.67	478,001	13.96	400,302	13.96	400,302
392.10	TRANSPORTATION EQUIPMENT - AUTOMOBILES	1.78	5,742	6.23	20,109	6.23	20,109
392.30	TRANSPORTATION EQUIPMENT - AIRCRAFT	3.79	97,790	8.62	222,334	8.62	222,334
392.40	TRANSPORTATION EQUIPMENT - SMALL TRUCKS	3.45	615,138	3.58	638,683	3.58	638,683
392.50	TRANSPORTATION EQUIPMENT - MISC.	9.45	49,427	1.49	7,816	1.49	7,816
392.60	TRANSPORTATION EQUIPMENT - LARGE TRUCKS (HYD)	4.72	1,059,533	3.69	829,351	3.69	829,351
392.70	TRANSPORTATION EQUIP. - LARGE TRUCKS (NON-HYD)	4.26	161,702	2.39	90,686	2.39	90,686
392.90	TRANSPORTATION EQUIPMENT - TRAILERS	1.93	68,539	1.99	70,776	1.99	70,776
393.00	STORES EQUIPMENT	7.89	77,508	5.40	53,001	5.40	53,001

IDAHO POWER COMPANY
COMPARISON OF CURRENT, FILED AND SETTLEMENT ACCRUAL RATES AND AMOUNTS

	ACCOUNT (1)	CURRENT ACCRUAL RATE	ACCRUAL AMOUNT	AS FILED ACCRUAL RATE	ACCRUAL AMOUNT	SETTLEMENT ACCRUAL RATE	ACCRUAL AMOUNT
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	8.31	350,872	4.84	204,375	4.84	204,375
395.00	LABORATORY EQUIPMENT	6.53	637,402	5.39	526,113	5.39	526,113
396.00	POWER OPERATED EQUIPMENT	6.99	510,758	6.95	507,497	6.95	507,497
397.10	COMMUNICATION EQUIPMENT - TELEPHONES	11.61	802,716	6.16	425,792	6.16	425,792
397.20	COMMUNICATION EQUIPMENT - MICROWAVES	9.99	1,721,643	6.99	1,204,847	6.99	1,204,847
397.30	COMMUNICATION EQUIPMENT - RADIO	9.99	262,084	8.36	219,374	8.36	219,374
397.40	COMMUNICATION EQUIPMENT - FIBER OPTIC	16.45	234,528	8.20	116,956	8.20	116,956
398.00	MISCELLANEOUS EQUIPMENT	8.50	247,380	9.57	278,626	9.57	278,626
	TOTAL GENERAL PLANT		14,605,110		13,435,820		13,435,820
	TOTAL DEPRECIABLE PLANT		95,971,920		89,258,469		87,457,498

ATTACHMENT NO. 7

Motion for Acceptance of Settlement Stipulation (IPUC Case No. IPC-E-08-06)

IDAHO POWER®
An IDACORP Company

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IDAHO PUBLIC
UTILITIES COMMISSION

LISA D. NORDSTROM
Senior Counsel

September 5, 2008

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-08-06
IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INSTITUTE REVISED DEPRECIATION RATES FOR ELECTRIC PLANT IN SERVICE

Dear Ms. Jewell:

Enclosed for filing are an original and seven (7) copies each of the Company's Motion for Acceptance of Settlement and the Stipulation executed by the Parties.

Also, I would appreciate it if you would return a stamped copy of this transmittal letter in the enclosed self-addressed, stamped envelope.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:csb
Enclosures

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Boise, ID 83702

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IDAHO PUBLIC
UTILITIES COMMISSION

Attorneys for Idaho Power Company

Street Address for Express Mail:
1221 West Idaho Street
Boise, Idaho 83702

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ORDER AUTHORIZING A CHANGE IN DEPRECIATION RATES APPLICABLE TO ELECTRIC PROPERTY	CASE NO. IPC-E-08-06 MOTION FOR ACCEPTANCE OF SETTLEMENT

COME NOW, Idaho Power Company ("Idaho Power" or "Company") and the Staff of the Idaho Public Utilities Commission ("Staff"), both of whom are hereinafter collectively referred to as the "Parties," and, in accordance with *Idaho Code* § 61-525, RP 056, and RP 274-276, hereby move the Commission for an Order accepting the settlement negotiated by the Parties as embodied in the Stipulation filed contemporaneously with this Motion. This Motion is based on the following:

I. APPLICATION AND PROCEDURAL HISTORY

On April 1, 2008, Idaho Power filed an Application with the Idaho Public Utilities Commission ("IPUC" or the "Commission") requesting authority to institute revised depreciation rates for the Company's electric plant in service ("Application"). No major changes have been made to the Company's depreciation rates in the last five years.

The Company's depreciation rates last changed in December 2003 when the Commission issued Order No. 29363 in Case No. IPC-E-03-07. In its April 1, 2008, filing, the Company sought an accounting order approving revised depreciation rates that the Company would prospectively apply to its depreciable plant in service. The Company did not request to change its electric rates with the Application.

The proposed depreciation rates included in the Company's Application were based upon the results of a detailed depreciation study of the Company's electric plant in service as of December 31, 2006. On the basis of $3,467,925,739 of depreciable plant in service on December 31, 2006, and using the average service life procedure, Idaho Power requested depreciation changes in its Application that would have decreased the Company's total annual depreciation expense by $6,713,451.

Following the Commission's April 17, 2008, Notice of Application and Intervention Deadline (Order No. 30532), no petitions to intervene were filed. Analysis by the Staff evaluated Idaho Power's proposed depreciation rates with those used in the industry by similar companies. After a series of settlement discussions, on August 27, 2008, the Parties agreed to several adjustments to the Company's proposed depreciation expenses for certain accounts associated with steam production plant (Bridger), hydraulic production plant (Thousand Springs and Clear Lake), other production plant

(Salmon diesel generator), and transmission poles and fixtures. Staff accepted the depreciation accruals originally proposed by the Company in its Application for its other plant categories.

The changes agreed to by the Parties result in an overall reduction in the requested depreciation expense from about $89.3 million to $87.5 million. The Parties' settlement of this matter is embodied in the Stipulation filed contemporaneously with this Motion.

II.

The Parties agree that the Stipulation is in the public interest and that all of the terms of the Stipulation are fair, just, and reasonable. The Parties support adoption of the Stipulation and acceptance of the Stipulation by the Commission as a resolution of all the outstanding issues.

III.

The Parties negotiated the Stipulation as an integrated settlement document. The Parties to this case are signatories to the Stipulation. The Parties request that the Stipulation will be entered into the record as evidence in this proceeding. As a result, in accordance with RP 274, the Parties respectfully submit that an evidentiary hearing is not required.

NOW, THEREFORE, Idaho Power Company, on behalf of itself and of the Parties, requests the Commission issue its Order (1) accepting the Stipulation in settlement of all of the remaining issues in the case and (2) authorizing the agreed upon depreciation rates to become effective August 1, 2008.

Respectfully submitted this 5th day of September 2008.

Lisa D. Nordstrom

LISA D. NORDSTROM
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 5th day of September 2008 I served a true and correct copy of the MOTION FOR ACCEPTANCE OF SETTLEMENT upon the following named individuals by the method indicated below, and addressed to the following:

Weldon B. Stutzman	X Hand Delivered
Deputy Attorney General	____ U.S. Mail
Idaho Public Utilities Commission	____ Overnight Mail
472 West Washington Street	____ FAX
P.O. Box 83720	X Email Weldon.stutzman@puc.idaho.gov
Boise, Idaho 83720-0074	

Lisa D. Nordstrom

LISA D. NORDSTROM

ATTACHMENT NO. 8

IPUC Order No. 30639
(Case No. IPC-E-08-06)

Office of the Secretary
Service Date
September 12, 2008

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ORDER AUTHORIZING A CHANGE IN DEPRECIATION RATES APPLICABLE TO ELECTRIC PROPERTY	))))))	**CASE NO. IPC-E-08-06** **ORDER NO. 30639**

On April 1, 2008, Idaho Power Company filed an Application for an accounting order authorizing the Company to revise its depreciation rates for electric plant in service effective August 1, 2008. The Company's depreciation rates were last changed in October 2003. The depreciation rates proposed by the Company in this case are based on a study completed by Gannett Fleming, Inc. and are applicable to Idaho Power's electric plant in service as of December 31, 2006. The proposed depreciation rates are based on a straight-line, remaining-life method, and average service life procedure for all electric plant.

Based on depreciable electric plant in service at December 31, 2006 of \$3,467,925,739, the proposed changes in depreciation rates would result in a decrease of \$6,713,451 in the Company's total annual depreciation expense. Approximately \$6.2 million of the decrease would be allocated to Idaho Power's Idaho operations.

On April 17, 2008, the Commission issued a Notice of Application and Notice of Intervention Deadline in response to Idaho Power's Application. Order No. 30532. The period for filing petitions to intervene to become a party ended on May 8, 2008, with no petitions filed, leaving only the Company and Staff as parties. Thereafter, Staff and Idaho Power met in several informal workshops to review appropriate depreciation rates for the Company's electric plant.

On September 5, 2008, Idaho Power and Staff filed a Stipulation setting forth agreed-upon depreciation rates. The Stipulation identifies changes to the Company's proposal agreed to by the parties, primarily increases in the service life and life span of a steam generation plant and hydraulic production plants. The net effect of the agreed-upon changes is to further reduce the Company's annual depreciation expense from \$89.26 million, as proposed in the Application, to \$87.46 million. The parties also agreed to a detailed review in the next depreciation case of accrual rates for several plant assets, including Bridger Assets, Bennett Mountain, Clear Lake Hydraulic Production Plant, Meters, Computers and Corporate Aircraft. Idaho Power filed a

Motion with the Stipulation, asking the Commission to accept the Stipulation as filed and authorize the depreciation rates in the Stipulation to become effective as of August 1, 2008.

Commission Rule of Procedure 274 states that the Commission, when presented with a case stipulation, "will prescribe procedures appropriate to the nature of a settlement to consider the settlement." The Commission may "summarily accept settlement of an essentially private dispute that has no significant implications for regulatory law or policy or for other utilities or customers upon the written request of the affected parties." IDAPA 31 01.01.274. The Stipulation in this case is such a settlement; it does not significantly implicate regulatory law or policy or other utilities or customers.

We find that the depreciation rates set forth in the Stipulation, specifically in Attachment No. 1, are reasonable and in the public interest, and in accord with law and regulatory policy. The Commission therefore approves the Stipulation filed September 5, 2008, and we authorize an effective date of August 1, 2008 for the depreciation rates set forth in the Stipulation.

ORDER

IT IS HEREBY ORDERED that the depreciation rates for Idaho Power's electric plant as set forth in Attachment No. 1 to the Stipulation are approved. These rates are effective as of August 1, 2008. Attachment No. 1 is also attached to this Order.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 12th day of September 2008.

MACK A. REDFORD, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

JIM D. KEMPTON, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:IPC-E-08-06_ws2

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT									
	STEAM PRODUCTION PLANT									
310.20	LAND AND WATER RIGHTS	75-R4	*	0	203,015.26	133,168	69,847	3,209	1.58	21.8
311.00	STRUCTURES AND IMPROVEMENTS									
	Boardman	100-S1	*	(10)	13,664,764.34	10,401,832	4,629,409	204,502	1.50	22.6
	Jim Bridger	100-S1	*	(7)	63,198,974.93	46,843,278	20,779,625	957,574	1.52	21.7
	Valmy Unit 1	100-S1	*	(10)	29,417,622.31	21,939,527	10,419,858	442,158	1.50	23.6
	Valmy Unit 2	100-S1	*	(10)	24,255,332.32	15,671,964	11,008,903	402,266	1.66	27.4
	Total Account 311				*130,536,693.90*	*94,856,601*	*46,837,795*	*2,006,500*	*1.54*	*23.3*
312.10	BOILER PLANT EQUIPMENT - SCRUBBERS									
	Jim Bridger	60-R3	*	(7)	58,908,365.65	41,166,395	21,865,558	1,018,118	1.73	21.5
	Valmy Unit 2	60-R3	*	(5)	20,941,250.57	13,659,862	8,328,451	316,666	1.51	26.3
	Total Account 312.1				*79,849,616.22*	*54,826,257*	*30,194,009*	*1,334,784*	*1.67*	*22.6*
312.20	BOILER PLANT EQUIPMENT - OTHER									
	Boardman	70-R1.5	*	(5)	35,288,034.40	24,991,899	12,060,537	547,888	1.55	22.0
	Jim Bridger	70-R1.5	*	(7)	229,201,271.84	121,268,927	123,976,435	5,829,371	2.54	21.3
	Valmy Unit 1	70-R1.5	*	(5)	76,723,967.25	48,681,408	31,878,757	1,391,327	1.81	22.9
	Valmy Unit 2	70-R1.5	*	(5)	80,418,334.11	49,735,349	34,703,902	1,325,456	1.65	26.2
	Total Account 312.2				*421,631,607.60*	*244,677,583*	*202,619,631*	*9,094,042*	*2.16*	*22.3*
312.30	BOILER PLANT EQUIPMENT - RAILCARS									
	Boardman	25-R3		20	1,498,563.91	592,002	606,849	44,194	2.95	13.7
	Jim Bridger	25-R3		20	2,478,477.91	1,350,060	632,722	57,260	2.31	11.1
	Total Account 312.3				*3,977,041.82*	*1,942,062*	*1,239,571*	*101,454*	*2.55*	*12.2*
314.00	TURBOGENERATOR UNITS									
	Boardman	50-S0.5	*	(5)	12,082,591.21	6,914,586	5,772,136	282,044	2.33	20.5
	Jim Bridger	50-S0.5	*	(7)	68,938,574.30	32,920,951	40,843,324	2,061,912	2.99	19.8
	Valmy Unit 1	50-S0.5	*	(5)	17,109,524.14	11,887,785	6,077,214	301,882	1.76	20.1
	Valmy Unit 2	50-S0.5	*	(5)	24,455,252.30	15,405,938	10,272,077	449,977	1.84	22.8
	Total Account 314				*122,585,941.95*	*67,129,260*	*62,964,751*	*3,095,815*	*2.53*	*20.3*
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	Boardman	65-S1.5	*	0	4,099,075.54	3,187,420	911,655	42,951	1.05	21.2
	Jim Bridger	65-S1.5	*	(7)	25,368,186.72	20,271,169	6,872,790	342,507	1.35	20.1
	Valmy Unit 1	65-S1.5	*	0	15,908,284.23	11,276,003	4,632,281	208,945	1.31	22.2
	Valmy Unit 2	65-S1.5	*	0	15,983,662.93	10,012,750	5,970,914	232,254	1.45	25.7
	Total Account 315				*61,359,209.42*	*44,747,342*	*18,387,640*	*826,657*	*1.35*	*22.2*

ATTACHMENT
Case No. IPC-E-08-06
Order No. 30639

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Boardman	50-R0.5	*	(5)	1,695,292.87	839,166	940,893	45,979	2.71	20.5
	Jim Bridger	50-R0.5	*	(7)	4,859,302.37	3,107,280	2,092,174	105,818	2.18	19.8
	Valmy Unit 1	50-R0.5	*	(5)	3,066,769.39	1,784,820	1,435,289	68,204	2.22	21.0
	Valmy Unit 2	50-R0.5	*	(5)	1,686,053.18	905,737	864,619	36,244	2.15	23.9
	Total Account 316				*11,307,417.81*	*6,637,003*	*5,332,975*	*256,245*	*2.27*	*20.8*
316.10	MISCELLANEOUS POWER PLANT EQUIPMENT - AUTOMOBILES	10-L2.5		25	58,859.95	1,746	42,399	5,601	9.52	7.6
316.40	MISCELLANEOUS POWER PLANT EQUIPMENT - SMALL TRUCKS									
	Jim Bridger	10-L2.5		25	208,142.12	180,864	(24,757)	0	-	-
	Valmy Unit 1	10-L2.5		25	18,003.44	15,151	(1,648)	0	-	-
	Total Account 316.4				*226,145.56*	*196,015*	*(26,405)*	*0*	-	-
316.50	MISCELLANEOUS POWER PLANT EQUIPMENT - MISCELLANEOUS									
	Boardman	10-L2.5		25	41,585.39	6,149	25,040	2,900	6.97	8.6
	Jim Bridger	10-L2.5		25	23,360.90	10,238	7,283	958	4.10	7.6
	Valmy Unit 1	10-L2.5		25	59,433.94	16,251	28,324	3,529	5.94	8.0
	Total Account 316.5				*124,380.23*	*32,638*	*60,647*	*7,387*	*5.94*	*8.2*
316.70	MISCELLANEOUS POWER PLANT EQUIP.-LARGE TRUCKS	19-S2		25	251,360.52	25,575	162,945	9,760	3.88	16.7
316.80	MISCELLANEOUS POWER PLANT EQUIP.-POWER OPERATED EQ	16-S0		30	1,114,431.30	(579,840)	1,359,943	145,714	13.08	9.3
	TOTAL STEAM PRODUCTION PLANT				**833,225,721.54**	**514,625,410**	**369,245,748**	**16,887,168**	**2.03**	
	HYDRAULIC PRODUCTION PLANT									
331.00	STRUCTURES AND IMPROVEMENTS									
	Hagerman Maintenance Shop	100-R2.5	*	(25)	1,558,200.45	588,724	1,359,027	64,117	4.11	21.2
	Milner Dam	100-R2.5	*	(25)	814,224.25	230,854	786,926	13,990	1.72	56.3
	Niagara Springs Hatchery	100-R2.5	*	(25)	5,029,555.80	1,275,880	5,011,064	179,766	3.57	27.9
	Hells Canyon Maintenance Shop	100-R2.5	*	(25)	1,604,833.95	566,934	1,439,107	51,501	3.21	27.9
	Rapid River Hatchery	100-R2.5	*	(25)	2,402,683.49	928,540	2,074,814	74,310	3.09	27.9
	American Falls	100-R2.5	*	(25)	11,857,401.29	6,038,675	8,783,073	197,107	1.66	44.6
	Brownlee	100-R2.5	*	(25)	30,068,208.63	17,491,534	20,093,727	726,270	2.42	27.7
	Bliss	100-R2.5	*	(25)	666,848.63	400,703	432,861	17,049	2.56	25.4
	Cascade	100-R2.5	*	(25)	7,364,153.73	3,051,973	6,153,221	123,336	1.67	49.9
	Clear Lake	100-R2.5	*	(25)	193,278.70	178,418	63,181	4,730	2.45	13.4
	Hells Canyon	100-R2.5	*	(25)	2,403,495.64	894,612	2,109,757	76,124	3.17	27.7
	Lower Malad	100-R2.5	*	(25)	600,746.78	373,630	377,303	15,214	2.53	24.8
	Lower Salmon	100-R2.5	*	(25)	888,303.03	527,177	583,200	22,849	2.57	25.5
	Milner	100-R2.5	*	(25)	9,512,589.19	2,729,102	9,161,634	159,676	1.68	57.4
	Oxbow Hatchery	100-R2.5	*	(25)	1,472,035.50	726,845	1,113,198	40,052	2.72	27.8
	Oxbow	100-R2.5	*	(25)	9,830,938.42	4,836,770	7,451,902	273,365	2.78	27.3
	Oxbow Common	100-R2.5	*	(25)	111,952.27	111,952	27,988	1,038	0.93	27.0
	Pahsimerio Accum. Ponds	100-R2.5	*	(25)	4,187,993.72	299,623	4,935,370	175,424	4.19	28.1
	Pahsimerio Trapping	100-R2.5	*	(25)	935,129.61	547,693	621,219	22,406	2.40	27.7
	Shoshone Falls	100-R2.5	*	(25)	1,139,956.09	668,822	756,120	32,266	2.83	23.4

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	STRUCTURES AND IMPROVEMENTS, cont.									
	Strike	100-R2.5	*	(25)	2,789,968.67	1,649,271	1,838,190	76,335	2.74	24.1
	Swan Falls	100-R2.5	*	(25)	25,223,735.85	6,914,133	24,615,536	753,550	2.99	32.7
	Twin Falls	100-R2.5	*	(25)	661,285.30	316,699	509,908	15,857	2.40	32.2
	Twin Falls (New)	100-R2.5	*	(25)	10,146,761.46	2,678,549	10,004,903	301,443	2.97	33.2
	Thousand Springs	100-R2.5	*	(25)	327,624.51	327,625	81,903	11,021	3.36	7.4
	Upper Malad	100-R2.5	*	(25)	357,819.86	274,952	172,323	7,041	1.97	24.5
	Upper Salmon A	100-R2.5	*	(25)	859,310.39	566,928	507,208	20,532	2.39	24.7
	Upper Salmon B	100-R2.5	*	(25)	326,935.58	151,070	257,600	10,033	3.07	25.7
	Upper Salmon Common	100-R2.5	*	(25)	352,331.39	153,746	286,668	11,100	3.15	25.8
	Total Account 331				*133,688,302.18*	*55,501,434*	*111,608,931*	*3,477,502*	*2.60*	*32.1*
332.10	RESERVOIRS, DAMS AND WATERWAYS - RELOCATION									
	Brownlee	90-S4	*	(20)	8,639,663.66	4,592,743	5,774,853	212,233	2.46	27.2
	Hells Canyon	90-S4	*	(20)	940,788.93	462,648	666,299	24,487	2.60	27.2
	Oxbow	90-S4	*	(20)	56,309.00	29,019	38,552	1,417	2.52	27.2
	Oxbow Common	90-S4	*	(20)	1,927,919.83	1,224,350	1,089,153	39,664	2.06	27.5
	Brownlee Common	90-S4	*	(20)	7,895,824.78	5,019,821	4,455,169	163,733	2.07	27.2
	Total Account 332.1				*19,460,506.20*	*11,328,581*	*12,024,026*	*441,534*	*2.27*	27.2
332.20	RESERVOIRS, DAMS AND WATERWAYS									
	Milner Dam	90-S4	*	(20)	614,874.97	172,994	564,856	9,559	1.55	59.1
	American Falls	90-S4	*	(20)	4,242,904.39	2,438,545	2,652,940	57,114	1.35	46.5
	Brownlee	90-S4	*	(20)	52,631,542.49	31,583,559	31,574,292	1,143,926	2.17	27.6
	Bliss	90-S4	*	(20)	7,480,783.71	5,874,296	3,102,646	131,012	1.75	23.7
	Cascade	90-S4	*	(20)	3,145,630.46	1,335,517	2,439,240	46,756	1.49	52.2
	Clear Lake	90-S4	*	(20)	584,984.73	450,439	251,543	18,715	3.20	13.4
	Hells Canyon	90-S4	*	(20)	51,724,316.81	25,151,853	36,917,327	1,316,438	2.55	28.0
	Lower Malad	90-S4	*	(20)	2,078,537.32	1,484,241	1,010,005	41,380	1.99	24.4
	Lower Salmon	90-S4	*	(20)	6,602,823.37	4,705,338	3,218,051	134,181	2.03	24.0
	Milner	90-S4	*	(20)	16,532,174.93	4,635,107	15,203,504	252,333	1.53	60.3
	Oxbow	90-S4	*	(20)	30,319,404.87	16,297,679	20,085,606	731,526	2.41	27.5
	Oxbow Common	90-S4	*	(20)	9,871.65	4,162	7,684	269	2.72	28.6
	Shoshone Falls	90-S4	*	(20)	512,401.48	478,649	136,233	8,809	1.72	15.5
	Strike	90-S4	*	(20)	9,764,915.58	7,374,540	4,343,360	187,848	1.92	23.1
	Swan Falls	90-S4	*	(20)	13,641,458.81	5,426,542	10,943,208	329,280	2.41	33.2
	Twin Falls	90-S4	*	(20)	263,089.08	203,663	112,044	4,996	1.90	22.4
	Twin Falls (New)	90-S4	*	(20)	7,669,627.33	1,604,132	7,599,420	223,512	2.91	34.0
	Thousand Springs	90-S4	*	(20)	2,083,442.82	2,083,443	416,690	55,559	2.67	7.5
	Upper Malad	90-S4	*	(20)	1,292,528.44	1,009,149	541,886	23,284	1.80	23.3
	Upper Salmon A	90-S4	*	(20)	1,153,590.73	342,659	1,041,650	42,594	3.69	24.5
	Upper Salmon B	90-S4	*	(20)	2,758,487.94	1,945,794	1,364,392	56,122	2.03	24.3
	Upper Salmon Common	90-S4	*	(20)	730,039.01	462,019	414,028	17,944	2.46	23.1
	Hells Canyon Common	90-S4	*	(20)	3,723,168.70	2,606,285	1,861,518	65,487	1.76	28.4
	Total Account 332.2				*219,560,599.62*	*117,670,605*	*145,802,123*	*4,898,644*	2.23	29.8
332.30	RESERVOIRS, DAMS AND WATERWAYS - NEZ PERCE	Square	*	0	5,599,934.61	1,006,639	4,593,296	160,717	2.87	28.6

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	Milner Dam	80-R3	*	(5)	878,005.87	210,871	711,035	13,153	1.50	54.1
	American Falls	80-R3	*	(5)	26,401,757.45	12,972,335	14,749,510	351,166	1.33	42.0
	Brownlee	80-R3	*	(5)	41,621,633.25	24,952,949	18,749,765	692,584	1.66	27.1
	Bliss	80-R3	*	(5)	4,367,360.46	2,949,965	1,635,762	69,661	1.60	23.5
	Cascade	80-R3	*	(5)	9,087,779.30	3,388,774	6,153,395	130,379	1.43	47.2
	Clear Lake	80-R3	*	(5)	742,499.27	82,179	697,446	51,982	7.00	13.4
	Hells Canyon	80-R3	*	(5)	10,936,002.51	3,941,566	7,541,238	284,219	2.60	26.5
	Lower Malad	80-R3	*	(5)	528,365.79	390,110	164,673	7,357	1.39	22.4
	Lower Salmon	80-R3	*	(5)	4,472,826.76	3,222,402	1,474,065	63,203	1.41	23.3
	Milner	80-R3	*	(5)	23,352,421.08	5,440,945	19,079,097	347,172	1.49	55.0
	Oxbow	80-R3	*	(5)	10,849,416.56	5,703,638	5,688,249	219,701	2.03	25.9
	Shoshone Falls	80-R3	*	(5)	1,624,269.34	749,464	956,018	41,504	2.56	23.0
	Strike	80-R3	*	(5)	4,674,860.58	3,215,915	1,692,689	74,596	1.60	22.7
	Swan Falls	80-R3	*	(5)	25,775,660.82	6,244,039	20,820,406	638,355	2.48	32.6
	Twin Falls	80-R3	*	(5)	1,430,443.99	257,847	1,244,119	38,915	2.72	32.0
	Twin Falls (New)	80-R3	*	(5)	15,678,462.57	3,498,786	12,963,600	391,295	2.50	33.1
	Thousand Springs	80-R3	*	(5)	729,122.94	521,519	244,062	32,696	4.48	7.5
	Upper Malad	80-R3	*	(5)	476,485.37	333,132	167,178	7,249	1.52	23.1
	Upper Salmon A	80-R3	*	(5)	1,191,919.73	607,043	644,472	26,398	2.21	24.4
	Upper Salmon B	80-R3	*	(5)	2,621,614.05	739,588	2,013,106	78,786	3.01	25.6
	Total Account 333				*187,440,907.69*	*79,423,067*	*117,389,885*	*3,560,371*	*1.90*	33.0
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	Hagerman Maintenance Shop	50-R1.5	*	(5)	39,066.76	8,428	32,592	1,635	4.19	19.9
	Milner Dam	50-R1.5	*	(5)	270,948.91	80,106	204,390	5,429	2.00	37.7
	American Falls	50-R1.5	*	(5)	2,846,961.70	1,290,882	1,698,428	56,489	1.98	30.1
	Brownlee	50-R1.5	*	(5)	6,754,737.98	2,954,232	4,138,246	172,643	2.56	24.0
	Bliss	50-R1.5	*	(5)	1,885,123.93	181,345	1,798,035	74,840	3.97	24.0
	Cascade	50-R1.5	*	(5)	2,208,492.78	149,174	2,169,743	64,124	2.90	33.8
	Clear Lake	50-R1.5	*	(5)	96,497.80	91,125	10,197	807	0.84	12.6
	Hells Canyon	50-R1.5	*	(5)	3,361,249.91	671,330	2,857,984	120,257	3.58	23.8
	Lower Malad	50-R1.5	*	(5)	351,745.67	87,525	281,806	12,867	3.66	21.9
	Lower Salmon	50-R1.5	*	(5)	1,701,455.57	398,215	1,388,314	59,768	3.51	23.2
	Milner	50-R1.5	*	(5)	2,336,451.70	608,095	1,845,179	47,294	2.02	39.0
	Oxbow	50-R1.5	*	(5)	3,071,574.65	883,426	2,341,727	99,056	3.22	23.6
	Shoshone Falls	50-R1.5	*	(5)	383,367.51	167,847	234,686	11,534	3.01	20.4
	Strike	50-R1.5	*	(5)	2,005,701.48	526,901	1,579,086	71,377	3.56	22.1
	Swan Falls	50-R1.5	*	(5)	3,110,642.15	825,248	2,440,926	85,182	2.74	28.7
	Twin Falls	50-R1.5	*	(5)	538,522.21	45,023	520,424	18,380	3.41	28.3
	Twin Falls (New)	50-R1.5	*	(5)	2,240,671.31	547,716	1,804,987	61,888	2.76	29.2
	Thousand Springs	50-R1.5	*	(5)	752,163.68	466,758	323,013	44,135	5.87	7.3
	Upper Malad	50-R1.5	*	(5)	392,637.15	70,374	341,895	14,721	3.75	23.2
	Upper Salmon A	50-R1.5	*	(5)	1,207,098.47	316,302	951,152	41,434	3.43	23.0
	Upper Salmon B	50-R1.5	*	(5)	1,220,362.84	302,775	978,606	41,566	3.41	23.5
	Total Account 334				*36,775,474.16*	*10,672,827*	*27,941,416*	*1,105,426*	*3.01*	25.3

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Hagerman Maintenance Shop	90-R2	*	0	976,871.66	337,013	639,861	30,435	3.12	21.0
	Milner Dam	90-R2	*	0	48,307.16	9,127	39,181	720	1.49	54.4
	Niagara Springs Hatchery	90-R2	*	0	73,522.57	17,040	56,483	2,039	2.77	27.7
	Hells Canyon Maintenance Shop	90-R2	*	0	799,451.96	247,742	551,708	19,941	2.49	27.7
	Rapid River Hatchery	90-R2	*	0	29,848.16	12,905	16,943	621	2.08	27.3
	American Falls	90-R2	*	0	1,805,640.50	449,757	1,355,884	31,261	1.73	43.4
	Brownlee	90-R2	*	0	3,254,248.62	1,616,111	1,638,139	60,553	1.86	27.1
	Bliss	90-R2	*	0	562,062.64	201,451	360,612	14,148	2.52	25.5
	Cascade	90-R2	*	0	1,101,278.52	379,155	722,123	15,056	1.37	48.0
	Clear Lake	90-R2	*	0	22,720.55	6,584	16,136	1,210	5.33	13.3
	Hells Canyon	90-R2	*	0	736,374.99	306,584	429,789	16,159	2.19	26.6
	Lower Malad	90-R2	*	0	82,186.44	55,035	27,150	1,118	1.36	24.3
	Lower Salmon	90-R2	*	0	285,836.81	193,195	92,639	3,723	1.30	24.9
	Milner	90-R2	*	0	649,695.83	153,422	496,272	8,997	1.38	55.2
	Oxbow Hatchery	90-R2	*	0	10,959.41	234	10,725	387	3.53	27.7
	Oxbow	90-R2	*	0	800,618.15	258,834	541,783	20,007	2.50	27.1
	Pahsimerio Accum. Ponds	90-R2	*	0	10,992.98	1,552	9,441	341	3.10	27.7
	Pahsimerio Trapping	90-R2	*	0	13,001.12	324	12,676	467	3.59	27.1
	Shoshone Falls	90-R2	*	0	203,507.40	45,848	157,658	6,676	3.28	23.6
	Strike	90-R2	*	0	651,067.66	209,864	441,203	18,071	2.78	24.4
	Swan Falls	90-R2	*	0	1,420,261.42	339,300	1,080,964	33,598	2.37	32.2
	Twin Falls	90-R2	*	0	99,093.87	53,763	45,332	1,420	1.43	31.9
	Twin Falls (New)	90-R2	*	0	468,032.70	90,717	377,317	11,531	2.46	32.7
	Thousand Springs	90-R2	*	0	56,738.95	56,740	0	0	-	-
	Upper Malad	90-R2	*	0	78,664.05	55,242	23,422	970	1.23	24.2
	Upper Salmon A	90-R2	*	0	107,990.34	77,326	30,664	1,191	1.10	25.8
	Upper Salmon B	90-R2	*	0	180,897.28	89,871	91,027	3,608	1.99	25.2
	Upper Salmon Common	90-R2	*	0	1,930.37	528	1,402	54	2.80	26.0
	Total Account 335				*14,531,802.11*	*5,265,264*	*9,266,534*	*304,302*	*2.09*	30.5
335.10	MISCELLANEOUS POWER PLANT EQUIPMENT - EQUIPMENT	15-SQ		0	41,734.74	29,301	12,434	1,010	2.42	12.3
335.20	MISCELLANEOUS POWER PLANT EQUIPMENT - FURNITURE	20-SQ		0	392,652.62	244,490	148,163	13,876	3.53	10.7
335.30	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTER	5-SQ		0	653,750.14	475,312	178,437	89,248	13.65	2.0
336.00	ROADS, RAILROADS AND BRIDGES									
	Milner Dam	75-R3	*	0	12,737.21	2,530	10,207	194	1.52	52.6
	Niagara Springs Hatchery	75-R3	*	0	46,667.72	46,668	0	0	-	-
	Rapid River Hatchery	75-R3	*	0	7,197.39	7,197	0	0	-	-
	American Falls	75-R3	*	0	306,332.58	118,400	187,932	4,644	1.52	40.5
	Brownlee	75-R3	*	0	518,444.14	253,478	264,966	10,421	2.01	25.4
	Bliss	75-R3	*	0	486,476.64	189,405	297,071	11,585	2.38	25.6
	Cascade	75-R3	*	0	122,668.04	41,700	80,968	1,780	1.45	45.5
	Clear Lake	75-R3	*	0	11,097.30	10,657	440	35	0.32	12.6
	Hells Canyon	75-R3	*	0	819,191.89	494,335	324,857	12,820	1.56	25.3
	Lower Malad	75-R3	*	0	244,565.45	118,578	125,987	5,022	2.05	25.1
	Lower Salmon	75-R3	*	0	88,693.04	47,749	40,944	1,626	1.83	25.2
	Milner	75-R3	*	0	489,139.50	97,083	392,057	7,347	1.50	53.4
	Oxbow Hatchery	75-R3	*	0	3,070.44	3,070	0	0	-	-
	Oxbow	75-R3	*	0	565,842.36	245,248	320,595	13,235	2.34	24.2
	Pahsimerio Accum. Ponds	75-R3	*	0	26,502.74	21,010	5,493	204	0.77	26.9

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	ROADS, RAILROADS AND BRIDGES, cont.									
	Pahsimerio Trapping	75-R3	*	0	15,612.35	15,222	390	14	0.09	27.9
	Shoshone Falls	75-R3	*	0	51,383.40	36,807	14,577	779	1.52	18.7
	Strike	75-R3	*	0	238,870.92	173,076	65,795	3,016	1.26	21.8
	Swan Falls	75-R3	*	0	835,946.15	312,318	523,629	16,617	1.99	31.5
	Twin Falls	75-R3	*	0	893,773.50	314,396	579,377	18,122	2.03	32.0
	Twin Falls (New)	75-R3	*	0	1,023,829.64	211,075	812,755	24,659	2.41	33.0
	Thousand Springs	75-R3	*	0	52,910.46	45,228	7,683	1,029	1.94	7.5
	Upper Malad	75-R3	*	0	60,117.68	30,379	29,739	1,215	2.02	24.5
	Upper Salmon A	75-R3	*	0	1,650.89	661	990	38	2.30	26.1
	Upper Salmon Common	75-R3	*	0	27,708.47	27,708	0	0	-	-
	Total Account 336				*6,950,429.90*	*2,863,978*	*4,086,452*	*134,402*	*1.93*	*30.4*
	TOTAL HYDRAULIC PRODUCTION PLANT				**625,096,093.97**	**284,481,498**	**433,051,697**	**14,187,032**	**2.27**	
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	Salmon Diesel	Square	*	0	11,959.08	11,959	0	0	-	-
	Evander Andrews	Square	*	0	4,276,832.78	296,054	3,980,779	134,941	3.16	29.5
	Bennett Mountain	Square	*	0	1,012,940.68	50,665	962,276	27,892	2.75	34.5
	Total Account 341				*5,301,732.54*	*358,678*	*4,943,055*	*162,833*	*3.07*	*30.4*
342.00	FUEL HOLDERS									
	Salmon Diesel	Square	*	0	61,306.39	61,306	0	0	-	-
	Evander Andrews	Square	*	0	1,433,423.71	249,652	1,183,772	40,128	2.80	29.5
	Bennett Mountain	Square	*	0	2,025,881.34	101,331	1,924,550	55,784	2.75	34.5
	Total Account 342				*3,520,611.44*	*412,289*	*3,108,322*	*95,912*	*2.72*	*32.4*
343.00	PRIME MOVERS									
	Evander Andrews	Square	*	0	28,676,958.09	1,167,561	27,509,396	932,522	3.25	29.5
	Bennett Mountain	Square	*	0	1,280,075.86	63,332	1,216,744	35,268	2.76	34.5
	Total Account 343				*29,957,033.95*	*1,230,893*	*28,726,140*	*967,790*	*3.23*	*29.7*
344.00	GENERATORS									
	Salmon Diesel	Square	*	0	541,644.95	541,645	0	0	-	-
	Evander Andrews	Square	*	0	13,166,034.86	5,656,938	7,509,097	254,546	1.93	29.5
	Bennett Mountain	Square	*	0	47,977,781.77	(6,601,483)	54,579,265	1,582,007	3.30	34.5
	Total Account 344				*61,685,461.58*	*(402,900)*	*62,088,362*	*1,836,553*	*2.98*	*33.8*
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	Salmon Diesel	Square	*	0	285,139.96	68,989	216,151	20,586	7.22	10.5
	Evander Andrews	Square	*	0	2,877,127.34	267,373	2,609,755	88,467	3.07	29.5
	Bennett Mountain	Square	*	0	1,519,410.98	75,998	1,443,413	41,838	2.75	34.5
	Total Account 345				*4,681,678.28*	*412,360*	*4,269,319*	*150,891*	*3.22*	*28.3*

IDAHO POWER COMPANY
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CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Salmon Diesel	Square	*	0	1,004.50	259	746	72	7.17	10.4
	Evander Andrews	Square	*	0	1,380,971.70	354,602	1,026,370	34,792	2.52	29.5
	Bennett Mountain	Square	*	0	4,132.42	129	4,003	116	2.81	34.5
	Total Account 346				*1,386,108.62*	*354,990*	*1,031,119*	*34,980*	*2.52*	*29.5*
	TOTAL OTHER PRODUCTION PLANT				**106,532,626.41**	**2,366,310**	**104,166,317**	**3,248,959**	***3.05***	
	TRANSMISSION PLANT									
350.20	LAND RIGHTS AND EASEMENTS	65-R3		0	22,454,969.55	4,125,397	18,329,572	338,260	1.51	54.2
350.21	RIGHTS OF WAY	65-R3		0	3,837,633.30	171,293	3,666,340	57,533	1.50	63.7
352.00	STRUCTURES AND IMPROVEMENTS	60-R3		(30)	36,779,609.35	18,536,761	29,276,731	618,958	1.68	47.3
353.00	STATION EQUIPMENT	45-R1		(5)	245,790,680.50	78,937,911	179,142,305	5,061,625	2.06	35.4
354.00	TOWERS AND FIXTURES	65-S3		(25)	98,003,480.18	29,046,585	93,457,763	1,924,444	1.96	48.6
355.00	POLES AND FIXTURES	55-R2		(60)	77,282,149.59	43,843,782	79,807,657	2,174,304	2.81	36.7
356.00	OVERHEAD CONDUCTORS AND DEVICES	65-R1.5		(30)	120,017,113.68	44,636,909	111,385,340	2,305,954	1.92	48.3
359.00	ROADS AND TRAILS	65-R3		0	318,351.06	243,747	74,604	3,134	0.98	23.8
	TOTAL TRANSMISSION PLANT				**604,483,987.21**	**219,542,385**	**515,140,312**	**12,484,212**	**2.07**	
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	65-R2.5		(30)	20,494,136.28	6,687,719	19,954,660	379,681	1.85	52.6
362.00	STATION EQUIPMENT	50-R0.5		(5)	142,958,358.69	36,679,371	113,426,903	2,695,793	1.89	42.1
364.00	POLES, TOWERS AND FIXTURES	44-R1.5		(50)	194,701,581.47	89,991,024	202,061,348	6,407,092	3.29	31.5
365.00	OVERHEAD CONDUCTORS AND DEVICES	47-R0.5		(40)	98,919,000.73	36,125,365	102,361,235	2,917,577	2.95	35.1
366.00	UNDERGROUND CONDUIT	60-R2		(20)	43,631,618.27	8,876,804	43,481,140	849,496	1.95	51.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES	50-S0.5		(15)	162,350,092.50	55,349,272	131,353,327	3,199,488	1.97	41.1
368.00	LINE TRANSFORMERS	37-R1		5	318,764,969.11	138,262,721	164,564,000	5,337,672	1.67	30.8
369.00	SERVICES	35-R2.5		(40)	51,272,290.59	31,266,977	40,514,230	1,583,874	3.09	25.6
370.00	METERS	20-O1		0	48,196,011.03	8,475,983	39,720,024	3,350,581	6.95	11.9
370.10	METERS - AMR EQUIPMENT	15-S3		0	4,426,243.43	104,830	4,321,414	299,334	6.76	14.4
371.10	PHOTOVOLTAIC INSTALLATIONS	10-S4		(5)	359,317.71	359,318	17,966	13,219	3.68	1.4
371.20	INSTALLATION ON CUSTOMER PREMISES	15-R2		(5)	2,274,716.24	2,190,308	198,144	14,274	0.63	13.9
373.20	STREET LIGHTING AND SIGNAL SYSTEMS	25-R1.5		(25)	4,067,069.77	2,771,816	2,312,019	166,226	4.09	13.9
	TOTAL DISTRIBUTION PLANT				**1,092,415,405.82**	**417,141,508**	**864,286,410**	**27,214,307**	**2.49**	
	GENERAL PLANT									
390.11	STRUCTURES AND IMPROVEMENTS - CHQ BUILDING	100-S1.5	*	(5)	25,833,040.80	6,460,650	20,664,043	614,746	2.38	33.6
390.12	STRUCTURES AND IMPROVEMENTS - EXCL. CHQ BLDG	50-L2		(5)	31,212,783.91	7,456,277	25,317,150	697,970	2.24	36.3
390.20	LEASEHOLD IMPROVEMENTS	30-S3		0	7,345,253.07	3,413,752	3,931,501	189,347	2.58	20.8
391.10	OFFICE FURNITURE & EQUIPMENT - FURNITURE	20-SQ		0	11,786,383.96	5,748,949	6,037,436	585,505	4.97	10.3
391.20	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	5-SQ		0	22,696,314.19	10,863,401	11,832,913	5,531,614	24.37	2.1
391.21	OFFICE FURNITURE & EQUIPMENT - EDP EQUIP.	7-L4		0	2,867,432.50	1,301,416	1,566,016	400,302	13.96	3.9
392.10	TRANSPORTATION EQUIPMENT - AUTOMOBILES	10-L2.5		25	322,580.19	124,143	117,792	20,109	6.23	5.9
392.30	TRANSPORTATION EQUIPMENT - AIRCRAFT	8-S2.5		50	2,580,219.74	333,471	956,640	222,334	8.62	4.3

IDAHO POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
392.40	TRANSPORTATION EQUIPMENT - SMALL TRUCKS	10-L2.5	25	17,830,083.75	8,707,876	4,664,689	638,683	3.58	7.3
392.50	TRANSPORTATION EQUIPMENT - MISC.	10-L2.5	25	523,039.68	325,373	66,909	7,816	1.49	8.6
392.60	TRANSPORTATION EQUIPMENT - LARGE TRUCKS (HYD)	19-S2	25	22,447,727.51	6,899,432	9,936,364	829,351	3.69	12.0
392.70	TRANSPORTATION EQUIP. - LARGE TRUCKS (NON-HYD)	19-S2	25	3,795,829.55	1,764,183	1,082,690	90,686	2.39	11.9
392.90	TRANSPORTATION EQUIPMENT - TRAILERS	30-S1.5	25	3,551,268.75	1,166,923	1,496,527	70,776	1.99	21.1
393.00	STORES EQUIPMENT	25-SQ	0	982,360.91	467,709	514,653	53,001	5.40	9.7
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	20-SQ	0	4,222,287.57	1,826,861	2,395,426	204,375	4.84	11.7
395.00	LABORATORY EQUIPMENT	20-SQ	0	9,761,135.63	4,419,489	5,341,646	526,113	5.39	10.2
396.00	POWER OPERATED EQUIPMENT	16-S0	30	7,306,984.97	1,580,752	3,534,141	507,497	6.95	7.0
397.10	COMMUNICATION EQUIPMENT - TELEPHONES	15-SQ	0	6,914,005.40	3,654,968	3,259,038	425,792	6.16	7.7
397.20	COMMUNICATION EQUIPMENT - MICROWAVES	15-SQ	0	17,233,659.37	5,709,382	11,524,279	1,204,847	6.99	9.6
397.30	COMMUNICATION EQUIPMENT - RADIO	15-SQ	0	2,623,458.46	1,176,789	1,446,672	219,374	8.36	6.6
397.40	COMMUNICATION EQUIPMENT - FIBER OPTIC	10-SQ	0	1,425,704.34	776,047	649,657	116,956	8.20	5.6
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	0	2,910,349.72	979,897	1,930,454	278,626	9.57	6.9
	TOTAL GENERAL PLANT			**206,171,903.97**	**75,157,740**	**118,266,636**	**13,435,820**	**6.52**	
	TOTAL DEPRECIABLE PLANT			**3,467,925,738.92**	**1,513,314,851**	**2,404,157,120**	**87,457,498**	**2.52**	
	NONDEPRECIABLE PLANT								
310.10	LAND			1,167,304.15					
330.00	LAND			22,523,450.15					
340.00	LAND			402,745.39					
350.00	LAND			2,460,259.88					
360.00	LAND			4,607,314.94					
389.00	LAND			8,760,764.66					
	TOTAL NONDEPRECIABLE PLANT			**39,921,839.17**					
	TOTAL ELECTRIC PLANT			**3,507,847,578.09**	**1,513,314,851**	**2,404,157,120**	**87,457,498**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE. ACTUAL LIFE SPAN FOR EACH FACILITY IS SHOW BEGINNING ON PAGE II-27 OF THIS REPORT.

ATTACHMENT NO. 9

OPUC Order No. 04-290
(Case No. UM 1120)

05-27-04 P12:43 IN

ORDER NO. 04 290

ENTERED MAY 24 2004

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1120

In the Matter of	)	
	)	
IDAHO POWER COMPANY	)	ORDER
	)	
Application for Revised Depreciation Rates.	)	
	)	

DISPOSITION: STIPULATION ADOPTED; DEPRECIATION RATES APPROVED

On November 18, 2003, Idaho Power Company (Idaho Power) filed an application for an order approving a change in its depreciation rates. Idaho Power requests authority to institute revised depreciation rates for the company's electric plant-in-service in the same manner approved by the Idaho Public Utility Commission (IPUC). In its Order No. 29363, the IPUC adopted a settlement that increased Idaho Power's annual depreciation expense by $4.3 million. If adopted here, the proposed changes would result in an annual Oregon jurisdiction expense increase of approximately $220,271. Idaho Power does not request any change to its electric rates.

On May 4, 2004, the Commission Staff (Staff) and Idaho Power filed a stipulation for Commission review. The stipulation is attached as Appendix A and incorporated by reference. Staff has reviewed Idaho Power's depreciation study and supporting documents, as well as information from the IPUC proceeding. Staff agrees that the rates adopted by the IPUC and proposed in the study are reasonable and should be adopted in Oregon. No other entities have sought or secured party status in this docket.

Commission Resolution

The Commission concludes that the stipulation is reasonable and should be adopted for two primary reasons. First, Staff explains that, based on its extensive review of this matter, the rates adopted by the IPUC are reasonable. Second, Staff believes this Commission should adopt a similar set of rates for cost efficiency for Idaho Power. With differing rates, Idaho Power would be required to track two sets of depreciation expenses for the same piece of plant. Because Oregon accounts for only 5.11 percent of the overall expense, we agree with Staff that a separate set of depreciation rates would not be cost justified.

ORDER

IT IS ORDERED that the stipulation, set forth in Appendix A, is adopted. The stipulated depreciation rates for Idaho Power Company shall become effective for accounting purposes on December 1, 2003.

Made, entered, and effective MAY 24 2004.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1120

In the Matter of the Application of Idaho Power Company for an Order Authorizing a Change in Depreciation Rates Applicable to Electric Property.	STIPULATION BETWEEN STAFF AND IDAHO POWER

This Stipulation is entered into for the purpose of resolving all issues regarding Idaho Power's application seeking a change in depreciation rates applicable to the Company's electric plant.

PARTIES

1. The initial parties to this Stipulation are Idaho Power and the Staff of the Public Utility Commission of Oregon ("Staff"). No other entities have sought or secured party status in this Docket.

INTRODUCTION

2. On November 17, 2003, Idaho Power Company ("Idaho Power" or "Company") commenced the proceeding in Oregon by filing its Application for an Order Approving a Change in Depreciation Rates ("Application"). The changes in depreciation rates proposed by Idaho Power would result in an annual Oregon jurisdictional expense increase of approximately $220,271. Concurrently filed, in support of the Company's Application, was the testimony and depreciation study of Gannett Fleming, by John J. Spanos, based on Idaho Power's electric property as of December 31, 2001. Also concurrently filed was a copy of the stipulation submitted to the Idaho Public Utility Commission ("IPUC"), and the Order issued by the IPUC. Although the Company's total annual depreciation expense would increase under its proposal, the Company did not make a request to change its electric rates with the Application.

On May 6, 2003, before filing an Application in Oregon, Idaho Power filed an Application with the IPUC requesting authority to institute revised depreciation rates. On August 11, 2003, Idaho Power and the Parties reached an agreement that resulted in a reduction in Idaho Power's requested increase in its annual depreciation expense from $7.0 million to $4.3 million. The $220,271 rate increase proposed in Oregon is based on Oregon's 5.11 percent share of the $4.3 million.

3. On January 9, 2004, Administrative Law Judge Michael Grant conducted a prehearing telephone conference to identify parties and to establish a procedural schedule. Pursuant to the schedule established by Michael Grant, on February 12, 2004, Staff presented its position on Idaho Power's depreciation Application to the parties. Staff found the rates proposed by Idaho Power reasonable. The agreement between Staff and Idaho Power obviated the scheduled Settlement Conference set for February 26, 2004.

4. Stipulation Exhibit No. 1, attached hereto and incorporated by this reference, sets forth the detailed account-by-account depreciation rates that parties agree should be adopted by the Commission.

POSITIONS OF THE PARTIES

5. The Company's proposed depreciation rates, and their justification, are set forth in the Study and in the stipulation reached with the Idaho Commission that was filed with its Application. Prior to filing in Oregon, on May 6, 2003, Idaho Power filed an Application with the IPUC requesting authority to institute revised depreciation rates for the Company's electric plant in service. The original Application filed in Idaho, by Idaho Power, would have increased annual depreciation expense by $7.0 million; the stipulated rates reduced the increase to $4.3 million. Oregon's share of this annual increase, if the revised rates were to be adopted, is $220,271.

6. The $4.3 million increase in annual depreciation expense agreed to by the IPUC is the result of totaling the changes in the plant categories: a $1.119 million decrease in Production expense, a $0.109 million increase in Transmission expense, a $5.142 million decrease in Distribution expense, and a $10.463 million increase in General expense. Similarly, the $220,271 increase in annual depreciation expense being proposed for Oregon is the result of totaling the changes in the following plant categories: a $57,160 decrease in Production expense, a $5,567 increase in Transmission expense, a $262,780 decrease in Distribution expense, and a $534,645 increase in General expense.

7. Staff has reviewed the depreciation study and supporting documentation, the IPUC's Order, and the IPUC's staff comments. Staff and Idaho Power agree that the rates adopted by the Idaho Commission and proposed in the study (see Attachment 1) are reasonable and should be adopted.

TERMS OF THE SETTLEMENT AGREEMENT

8. Next Company Depreciation Study and Filing. The Parties agree that Idaho Power shall file its next depreciation study and application with the Commission no later than five years after the Commission's final order in this Docket.

GENERAL TERMS AND CONDITIONS

9. The Parties agree that this Stipulation is in the public interest and all of its terms and conditions are fair, just, and reasonable. Other than the positions referenced above, and any testimony or comments, 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 negotiations relating to the Stipulation shall be treated as confidential and shall not be admissible as evidence in this or any other proceeding.

10. The Parties have negotiated this Stipulation as an integrated document. Accordingly, the Parties recommend that the Commission adopt the Stipulation in its entirety. If

the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

11. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein.

12. By entering into this Stipulation, no party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other party in arriving at the terms of this Stipulation. No party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

13. Effective Date. The Parties agree that this Stipulation shall, subject to Commission approval, take effect on December 1, 2003.

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

This Stipulation is entered into by each party on the date entered below such party's signature.

IDAHO POWER	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: [signature]	By: [signature]
Date: 3-25-04	Date: 4/27/04

APPENDIX A
PAGE 4 OF 4

ATTACHMENT NO. 10

Proposed Tariff Schedule 92
(OPUC Case No. UE ________)

SCHEDULE 92
DEPRECIATION ADJUSTMENT RIDER

PURPOSE

To recover from Customers the accelerated depreciation of the existing metering infrastructure that will be replaced by the installation of Advanced Metering Infrastructure (AMI) less the revenue requirement impact of the revised depreciation rates.

APPLICABILITY

This Schedule is applicable to all electric energy delivered to Customers served under Schedules 1, 7, 9 Secondary, and 24 Secondary.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after January 1, 2009, will be:

Schedule	Description	Adjustment Rate
1	Residential Service	0.1287¢ per kWh
7	Small General Service	0.1287¢ per kWh
9 Secondary	Large Power Service	0.1287¢ per kWh
24 Secondary	Irrigation Service	0.1287¢ per kWh

SPECIAL CONDITIONS

1. This Schedule will terminate within six months or less of the effective date if the Company does not commence mass deployment of meters by June 30, 2009.

2. This Schedule may be temporarily suspended in order to resolve specific issues identified during the mass deployment of meters. The Company must file an application to suspend at least 45 days before the termination deadline specified in Special Condition 1.

EXPIRATION

The Depreciation Adjustment Rider included on this Schedule will expire June 30, 2010.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

In the Matter of Idaho Power Company's	)
Application to Accelerate Depreciation	)
of Existing Metering Equipment to be	)
Replaced by Advanced Metering	)
Infrastructure ("AMI") Installation; and to	)
Implement Revised Depreciation Rates for	)
the Company's Electric Plant-In- Service	)
___________________________________	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GREGORY W. SAID

OCTOBER 3, 2008

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 ("the Company") as the Director of State Regulation in the Pricing and Regulatory Services Department.

Q. Please describe your educational background and business affiliations.

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 1996. I also managed the Company's involvement in establishing a Power Cost Adjustment mechanism in the Oregon jurisdiction. Recently, I was asked to manage rate design efforts in addition to revenue requirement issues. My title is now Director of State Regulation.

Q. What it the purpose of your testimony in this matter?

A. My testimony will provide an overview of this filing, provide a brief history of the Advanced Metering Infrastructure ("AMI") issue from the Company's perspective, and will address regulatory policy issues related to the revision of current depreciation rates and the deployment of on Idaho Power Company's system. . Specifically, these policy issues include: (1) the decision to pursue an AMI investment, (2) a discussion of the past interaction, reports, and Idaho Public Utilities Commission ("IPUC") orders on the subject, (3) the desired regulatory treatment of an AMI investment, (4) the importance of

Commission support of AMI cost recovery on the timing of Company investments in AMI, and (5) acceptance of the revised depreciation rates recently approved by the IPUC.

Q. Please provide an overview of this filing.

A. The Company's filing consists of an Application, my testimony, and the testimony of Ms. Courtney Waites, a Pricing Analyst with the Company. As an attachment to this filing, the Company has included the Application filed with the IPUC with regard to the AMI deployment and the testimony of Mr. Mark Heintzelman, a Delivery Services Leader in the Metering Department. Mr. Heintzelman's testimony from the Idaho filing describes the Company's AMI plans from a technical operations perspective and the contracts that the Company has entered into in order to implement the planned AMI deployment. Also attached to the Company's Oregon filing is a copy of the Application filed with the IPUC regarding the request to revise the current depreciation rates, as well as the IPUC Order approving revised depreciation rates. My testimony is intended to provide Company policy while, Ms. Waites' will provide the potential regulatory impacts of the AMI deployment, including the Company's capital cost estimate for our Oregon jurisdiction and a 2009 revenue requirement impact which incorporates the revised depreciation rates as well as the accelerated depreciation of the existing metering infrastructure that AMI will replace.

Q. What is the Company requesting of the Commission in this Application?

A. Idaho Power is requesting that the Commission approve the Company's request to begin accelerating the depreciation of the existing metering infrastructure as well as the corresponding cost recovery of this depreciation and to implement the revised depreciation rates for electric plant-in-service. The Company is asking the Commission to make a positive endorsement of future AMI investment based upon the operating benefits that AMI will provide, the Company's capital cost estimate for the total project, and the potential future benefits that AMI offers in terms of dynamic pricing and other Smart Grid opportunities.

Q. Are the future benefits you mentioned related to dynamic pricing and Smart Grid applications available as a result of the AMI deployment?

A. No. AMI will provide a platform from which the other benefits can launch, but additional investments will be required before wide scale applications of pricing, programs, and Smart Grid opportunities can become a reality. However, because Idaho Power's operational benefits alone can justify the investment in AMI, the Company and the Commission can evaluate additional investments and benefits as those opportunities emerge.

Q. Please describe the history of the AMI issue as it relates to Idaho Power and the IPUC.

A. One of the many interests spawned during the western energy crisis of 2000 and 2001 was the idea that new metering technology, along with time-of-use ("TOU") pricing could become part of the solution to future energy concerns. As a result, the IPUC ordered the Company to evaluate and report upon the viability of TOU metering programs and the deployment of Automated Meter Reading ("AMR") technology. Since that time, AMR has evolved into the more inclusive term AMI, which includes not only the metering devices but also the hardware, software, communications equipment, customer associated systems, and data management software.

In Case No. IPC-E-02-12, a docket opened to investigate TOU pricing for residential customers, the IPUC ordered Idaho Power to complete a full AMR installation by 2004. The implementation was subsequently postponed due to a number of financial, technical, and implementation problems encountered with meeting the time frame.

The IPUC then adopted a phased-in implementation along with a collaborative evaluation approach, while directing the Company to continue to work toward implementation of AMI technology "as soon as possible." The IPUC has continually stated that Idaho Power should be working toward the implementation of AMI technology as soon as possible and reiterated its finding in Order No. 30102 stating that "the potential benefits of advanced metering to ratepayers and the Company are too great to delay AMR implementation indefinitely."

Q. What is the desired regulatory treatment of the procurement and deployment of AMI?

A. As previously stated, Idaho Power has been assessing the value that AMI could bring to its customers for a number of years. As noted in the Company's AMI compliance report filed with the IPUC and dated August 31, 2007, Idaho Power plans a three-year deployment of AMI across its entire system beginning in 2009. The report, titled *Advanced Metering Infrastructure (AMI) Implementation Plan*, is Attachment No. 1 to the Application. On page four of that report, the Company articulates its regulatory needs for an AMI implementation. The report includes as regulatory needs: (1) a three-year depreciation of the meters and metering equipment that AMI will replace, (2) the recovery of new metering equipment as it is placed in service and the capture of Operating and Maintenance ("O&M") benefits as they begin to occur, and (3) the establishment of appropriate depreciation rates for AMI equipment.

Q. Please expand on the importance of accelerating the depreciation of existing metering equipment.

A. The accelerated depreciation of the existing metering equipment with corresponding rate recovery is a fundamental assumption in the Company's financial analysis of the AMI deployment. Although the report envisioned a three year depreciation of existing meters, Oregon Statute does not allow for recovery of depreciation expense once metering equipment is removed. As a result, the Company must collect an accelerated depreciation expense for existing meters prior to their replacement. Beginning the accelerated depreciation of the existing meters now avoids a stranded asset situation and the possibility of used and useful concerns as long as the accelerated depreciation is collected prior to the installation of AMI in the Oregon jurisdiction. In order to accomplish this goal, the Company is proposing an 18-month acceleration of depreciation for our Oregon jurisdiction. The Company also proposes simultaneous recovery of the accelerated depreciation via a tariff rider.

Q. Please expand on the importance of recovery for future AMI investment.

A. Although not part of this Application, the future revenue requirement associated with the installation of AMI will include the return on and return of the investment in metering equipment less the offsetting O&M benefits that will accrue as a result of our AMI deployment. Timely rate adjustments that recognize the impact of necessary returns offset by O&M benefits will support the Company's financing requirements as it continues to fund significant investments in system infrastructure.

Q. Please expand on the importance of establishing appropriate depreciation rates for AMI equipment.

A. The last changes to the Company's Oregon depreciation rates were set forth in OPUC Order No. 04-290, Case No. UM 1120. Depreciation rates were based on the Company's electric plant-in-service at December 31, 2001. On November 18, 2003, the Company requested permission from the OPUC to revise its depreciation rates and have them become effective for accounting purposes on December 1, 2003. In that case, the Oregon Commission recognized that the Idaho Commission had thoroughly reviewed and approved the Company's depreciation study and the resulting rates. The Oregon Staff reviewed the depreciation study and the supporting documentation. After evaluating and assessing the case, the Staff determined the rates approved in the Idaho Order were reasonable and should be adopted. On May 24, 2004, the Oregon Commission ordered the same stipulated depreciation rates that had been approved by the Idaho Commission in its Order No. 29363 dated October 22, 2003. Both the Idaho and Oregon revised depreciation rates became effective on December 1, 2003.

Similarly, in this filing, Idaho Power requests it be granted authority to institute revised depreciation rates for the Company's electric plant-in-service in exactly the same manner as that provided for in IPUC Order No. 30639. It is the opinion of the Company that this Order is reasonable and proper, in the public interest, and fair to ratepayers of the Company. Included in these revised depreciation rates are the appropriate depreciation rate for AMI equipment.

Idaho Power Company does approximately 5 percent of its business in the state of Oregon and it would be administratively difficult and extremely cumbersome if it were required to charge different depreciation rates in Oregon than the rates ordered in Idaho, where it does the overwhelming majority of its business. The Company believes that the IPUC's Order is appropriate and respectfully requests the Oregon Commission adopt the provisions of IPUC Order No. 30639 and authorize Idaho Power to institute revised depreciation rates in accordance with that Order. This would result in the same depreciation rates being in effect for the Company on a system-wide basis.

Q. What is the Company requesting with regard to the current depreciation rates?

A. The Company recently filed a request with the IPUC to implement revised depreciation rates as a result of a depreciation study performed by the firm Gannett Fleming regarding electric plant-in-service at December 31, 2006. In its Order No. 30639, the IPUC approved the Company and IPUC Staff's Stipulation agreement which resulted in a reduction to depreciation expense. The Company is requesting to be granted authority to implement the revised depreciation rates in its Oregon service territory effective August 1, 2008, with a change in customer rates effective January 2009 to coincide with the accelerated depreciation of the existing metering infrastructure.

Q. Over time why is AMI cost recovery important to Idaho Power?

A. AMI implementation will bring customer operational benefits and provide a foundation for acquiring customer information that can be used to develop energy efficiency programs and dynamic pricing. As a result, Idaho Power believes it is reasonable to pursue full implementation of AMI throughout its service territory staged over the next three years. However, the significant customer and economic growth that the Company has been experiencing also requires continued investments in infrastructure to connect and meet the energy needs of these customers. Additionally, there is an ongoing need to replace existing infrastructure to continue to reliably serve existing loads. Although AMI will provide benefits to customers, it is not an investment that is necessary for

Idaho Power to fulfill its obligation to meet new and existing service requirements. Accordingly, Commission support of AMI cost recovery is an important factor in the Company proceeding with implementation.

Q. Is it your opinion that the granting of the tariff proposed by the Company is in the public interest?

A. Yes. The proposed tariff will allow the Company to comply with the IPUC's directives regarding AMI and will allow Oregon customers the ability to share in the AMI benefits, while maintaining the Company's financial health as it continues to provide safe, reliable service at reasonable rates.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

In the Matter of Idaho Power Company's	)
Application to Accelerate Depreciation	)
of Existing Metering Equipment to be	)
Replaced by Advanced Metering	)
Infrastructure ("AMI") Installation; and to	)
Implement Revised Depreciation Rates for	)
the Company's Electric Plant-In- Service	)
______________________________________	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

COURTNEY WAITES

OCTOBER 3, 2008

Q. Please state your name and business address.

A. My name is Courtney Waites. 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 a Pricing Analyst.

Q. Please describe your educational background.

A. In December of 1998, I received a Bachelor of Arts degree in Accounting from the University of Alaska in Anchorage, Alaska. In 2000, I earned a Master of Business Administration degree from Alaska Pacific University. I have attended New Mexico State University's Center for Public Utilities and the National Association of Regulatory Utility Commissioners Practical Skills for the Changing Electric Industry conference and the Electric Utility Consultants, Inc., Introduction to Rate Design and Cost of Service Concepts and Techniques for Electric Utilities conference.

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

A. I became employed with Idaho Power Company in December 2004 in the Accounts Payable Department. In 2005, I accepted a Regulatory Accountant position in the Finance Department where one of my tasks was to assist responding to regulatory data requests pertaining to the finance scope of work. In 2006, I accepted my current position, a Pricing Analyst, in the Pricing and Regulatory Services Department. My duties as a Pricing Analyst include providing support for the Company's various regulatory activities including tariff administration, regulatory ratemaking and compliance filings, and the development of various pricing strategies and policies.

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

A. First, I will describe the costs associated with the Company's request to accelerate the depreciation of the existing metering equipment. Second, I will discuss the reduced depreciation costs associated with the latest depreciation study. Third I will address the capital costs associated with the three-year deployment of the Advanced Metering Infrastructure ("AMI") deployment ("Project"). Finally, I will describe the Company's estimate of the quantifiable Operations and Maintenance ("O&M") savings as a result of the deployment. Although the Company is not requesting the recovery of capital costs associated with the AMI deployment or reflecting the operational savings to be derived subsequent to deployment in this application, the Company believes that such information supports the current request.

Q. Why is the Company requesting to accelerate the depreciation of the existing metering equipment?

A. As Mr. Said stated in his testimony, the accelerated depreciation of the existing metering equipment with corresponding rate recovery is a fundamental assumption in the Company's financial analysis of the AMI deployment. But another driver is ORS 757.355, which requires the Company to collect the accelerated depreciation of the existing metering equipment prior to its replacement to ensure recovery. In order to ensure recovery as contemplated in ORS 757.355 and minimize the rate impact for customers, the Company is requesting to begin accelerating the depreciation and the corresponding rate recovery in January 2009.

Q. When does the Company anticipate replacing the existing meters?

A. The Company's three-year meter deployment plan calls for installation of the meters to begin in our Oregon service territory in October 2010. However, it is conceivable that deployment in Oregon could start as early as September 2010.

Q. How long do you anticipate the meter exchange will take?

A. The Company expects to complete the meter exchange in Oregon within 30 days.

Q. Why is it important to do the Oregon meter exchanges in September or October 2010?

A. In our contract with the meter exchange vendor, the Company has agreed to a per meter cost based on the area of installation. The vendor based this cost on the use of the same vendor facilities and staff as used in the Canyon County and Payette, Idaho deployment, anticipated to be complete in September, 2010, with the Oregon deployment scheduled immediately after. If the vendor does not move further west into the Oregon service territory following deployment in western Idaho, the schedule would necessarily change and deployment in Oregon would be shifted to follow the deployment across our Idaho service territory, or around the first part of 2012. At that time the vendor would have to establish new facilities to work from and hire a new workforce. In addition to costs associated with the meter exchange vendor, the Company's operational costs would also be impacted. A delay would reduce the efficiencies gained by the AMI implementation just across the border in Payette, Idaho due to an increase in O&M expenses associated with meter reading and service connects and disconnects resulting in lost economies of scale.

Q. What is the net plant value of the existing meters?

A. The Company estimates the net plant value of the existing meters on December 31, 2008, based on the actual net plant value as of March 31, 2008 and forecasted net plant values through December 31, 2008, will be $1,380,981.

Q. What would an 18-month straight line depreciation of the $1,380,981 reveal?

A. An 18-month straight line depreciation of $1,380,981 would result in monthly depreciation expense of $76,721 for January 2009 through June 2010, as can be seen on Exhibit 1. At that time, current investment in metering within the Oregon jurisdiction would be fully depreciated prior to the new AMI deployment.

Q. In the Application, the Company is requesting to offset the proposed rate increase associated with accelerating the depreciation of the existing metering equipment with the rate decrease associated with the

implementation of the new depreciation rates. What is the rate decrease associated with the implementation of the new depreciation rates?

A. Upon adoption of the proposed depreciation rates, the decrease to annual depreciation expense in Oregon would be approximately $416,355.

Q. Has the Company calculated an estimate of the annual revenue requirement to be recovered from customers for the accelerated depreciation of the existing metering equipment and the implementation of the new depreciation rates?

A. Yes. The estimated 2009 revenue requirement is $504,299, which is the annualized accelerated depreciation of $920,654 ($76,721 x 12 months) less the reduction in depreciation expense as a result of the new depreciation rates of $416,355. This equates to an overall increase of 1.47%, as shown on Exhibit 2. The increase will only affect those customer classes that will be a part of the AMI deployment, Schedules 1, 7, 9 Secondary, and 24 Secondary.

Q. How does the Company propose to recover the additional revenue requirement?

A. As Mr. Said mentioned in his testimony, the Company is proposing to implement a limited term tariff rider, Schedule 92 – Depreciation Adjustment Rider, shown in Attachment 10 to the Application. This tariff rider would be in effect for eighteen months, January 2009 through June 2010, and would collect the accelerated depreciation of the existing metering equipment less the decrease associated with the implementation of the new depreciation rates.

Q. You mentioned that although the Company is not requesting recovery of the capital costs associated with the AMI deployment or the reflection of the operational savings to be derived from the subsequent deployment, the Company believes this information supports the current request. What are the total anticipated capital costs associated with the Project?

A. The total capital costs associated with the Project and allocated to the Oregon jurisdiction are $3.64 million, as seen on Exhibit 1.

Q. What makes up the capital costs included in the $3.64 million?

A. This amount includes Information Technology ("IT") expenditures, meter costs, stations equipment expenses, plus additional costs the Company knows it will incur but cannot precisely quantify at this time. These additional costs include, but are not limited to, sales taxes, customer growth, fuel charges, additional IT hardware, software, and personnel time, and the cost of Idaho Power oversight of the Project. The total also covers contingencies, such as change orders and customer growth. However, this is an estimate and is subject to adjustment to account for documented, legally-required equipment changes and material changes in assumed escalation rates or growth rates not foreseen at the time of the Application.

Q. Please describe the IT expenditures included in the total capital costs.

A. The total IT expenditures associated with the AMI Project which would be allocated to the Oregon jurisdiction are $63,753, as shown on Exhibit 1. These expenses are related to the hardware and software installations and the testing and interface development of the Meter Data Management System and the TWACS Net Server. These expenses include the costs of servers, licenses, sales tax and labor with payroll loadings.

Q. Are there any costs included in the IT expenditures that the Company has identified as those that cannot be precisely quantified?

A. No. Although the IT expenditures include sales tax, the purchase of the products will occur during the year 2008, when the sales tax is known and measurable.

Q. Please describe the meter costs included in the total capital costs.

A. The meter costs associated with the AMI Project which would be allocated to the Oregon jurisdiction are $2,321,263, as shown on Exhibit 1. These costs are made up of three components: the meters, the TWACS communications modules, and the meter exchange services. As detailed in Attachment 4 to the Application, Mr. Heintzelman's testimony, Landis+Gyr Inc. ("Landis+Gyr") will supply the residential meters and General Electric Company ("GE") will supply the commercial meters. In the contract, Landis+Gyr has committed to a fixed price for five years and GE has committed to a fixed price for three years.

The Company has contracted with Aclara Power-Line Systems Inc. ("Aclara") to provide the TWACS communications modules with a five-year fixed price. These modules will be shipped directly to the meter manufacturers, Landis+Gyr and GE, for integration into the meters. The AMI equipped meter will then be shipped directly to Tru-Check, Inc. ("Tru-Check") the meter exchange vendor, which makes up the third component of the meter costs included in the total capital costs. Tru-Check will then install the AMI equipped meters throughout the Company's service territory at a per meter cost based on the area of installation, which is defined in the contract. Together, with stores loadings, sales tax and overheads, these three components make up the Oregon allocated meter costs of $2,321,263, shown in Exhibit 1, included in the total capital costs.

Q. Are there any costs included in the meter costs that the Company has identified as those that cannot be precisely quantified?

A. Yes. The meter costs include a sales tax assumption of six percent over the course of the three-year deployment. However, the sales tax is subject to change and could adjust the total meter costs upwards or downwards. Also, as part of the cost analysis, the Company forecasted customer growth and incorporated the associated meter costs into the capital costs. During the three-year deployment, the Company assumes a growth rate which averages 2.7% for the residential class, 2.5% for the commercial class, and 1.5% for the irrigation class. In addition, the Company negotiated a fuel escalation clause into the contract with Tru-Check, the meter installation vendor. The per meter installation cost by area included in the contract assumes a fuel cost of $4.00/gallon of gasoline. However, the fuel clause allows for a $0.01 per meter adjustment for every $0.10 movement in the price of gasoline. That is, if the price per gallon of gasoline goes up $0.10, Tru-Check is entitled an extra $0.01 per meter installed. Likewise, if the price per gallon of gasoline decreases, the Company's cost of installation per meter decreases at the same $0.10/$0.01 rate.

Q. Please describe the stations equipment expenses included in the total capital costs.

A. The total stations equipment expenses associated with the AMI Project and allocated to the Oregon jurisdiction are $1,257,876, as shown on Exhibit 1. This equipment is necessary for upgrades to the substations for the deployment of the Project which may include new modulation transformer units, third party backhaul communications/frame relays, control receiver units, outbound modulation units, inbound pickup units, other miscellaneous materials, and the Idaho Power labor associated with the stations upgrades. All station equipment material cost estimates are fully loaded with stores loading, sales tax, and overheads. The labor included in the estimate is also fully loaded.

Q. Are there any costs included in the stations equipment expenses that the Company has identified as those that cannot be precisely quantified?

A. Yes. The stations equipment expenses include the same sales tax assumption of six percent over the course of the three-year deployment as that assumed in the meter costs. Therefore, a change in the sales tax could adjust the total stations equipment expenses upwards or downwards.

Q. Are there any other costs associated with the AMI Project that are not included in the total capital costs?

A. No.

Q. What are the O&M benefits associated with the Project?

A. The Company expects quantifiable O&M benefits from the following areas: reduction in labor and transportation costs related to meter reading, regional operations benefit in confirming equipment outage to prevent crew dispatch, regional operations benefits in confirming service restored to prevent prolonged crew time in area, regional operations benefit on detecting overloaded distribution transformers, benefit with regards to the operation of the irrigation peak rewards program, and outage management operation benefits. The Oregon allocation of O&M benefits identified for the three-year deployment period are $447,932 and are shown on Exhibit 1.

Q. How does the Company propose that the Commission treat the total capital costs associated with the Project and resulting O&M benefits for ratemaking purposes?

A. At this time the Company is only requesting to begin accelerating the depreciation of the existing metering equipment and the corresponding rate recovery of the accelerated depreciation. Idaho Power will address the capital costs associated with the Project, with the offsetting O&M benefits, and the regulatory treatment of these costs and benefits in a subsequent filing.

Q. Does this conclude your testimony?

A. Yes, it does.

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total 2008
IT Capital Expenditures	-	-	-	-	2,797	178	3,461	3,461	3,461	-	-	-	$ 13,357
Meter & Installation costs	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Stations Investment	-	-	-	-	-	-	-	-	-	-	-	-	$ -
O&M Costs (Benefits)	-	-	-	-	-	-	-	-	-	-	-	-	$ -
													$ 13,357
Accelerated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	$ -

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total 2009
IT Capital Expenditures	919	919	919	919	919	919	919	919	919	919	919	919	$ 11,025
Meter & Installation costs	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Stations Investment	-	-	-	-	-	-	-	-	-	-	-	-	$ -
O&M Costs (Benefits)	-	-	-	-	-	-	-	-	-	-	-	-	$ -
													$ 11,025
Accelerated Depreciation	76,721	76,721	76,721	76,721	76,721	76,721	76,721	76,721	76,721	76,721	76,721	76,721	$ 920,654

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total 2010
IT Capital Expenditures	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	$ 35,462
Meter & Installation costs	191,351	191,351	191,351	191,351	191,351	191,351	191,351	191,351	191,351	191,351	191,351	191,351	$ 2,296,211
Stations Investment	-	-	-	-	104,111	429,241	440,756	283,768	-	-	-	-	$ 1,257,876
O&M Costs (Benefits)	8,821	8,821	8,821	8,821	(6,310)	(9,336)	(12,362)	(15,388)	(18,414)	(21,440)	(24,466)	(27,492)	$ (99,923)
													$ 3,589,549
Accelerated Depreciation	76,721	76,721	76,721	76,721	76,721	76,721				-	-	-	$ 460,327

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total 2011
IT Capital Expenditures	326	326	326	326	326	326	326	326	326	326	326	326	$ 3,909
Meter & Installation costs	732	1,829	1,829	1,829	1,829	1,829	2,529	2,529	2,529	2,529	2,529	2,529	$ 25,051
Stations Investment	-	-	-	-	-	-	-	-	-	-	-	-	$ -
O&M Costs (Benefits)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	(29,001)	$ (348,009)
													$ 28,960
Accelerated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	$ -

	Total
IT Capital Expenditures	$ 63,753
Meter & Installation costs	$ 2,321,263
Stations Investment	$ 1,257,876
O&M Costs (Benefits)	$ (447,932)
	$ 3,642,891
Accelerated Depreciation	$ 1,380,981

Idaho Power Company
Before the Public Utilities Commission of Oregon
State of Oregon
Current and Proposed Revenues
Associated with Normalized kWh for 12-Months Ending March 2009

Tariff Description	(1) Rate Schedule No	(2) Average No. of Customers	(3) Normalized kWh	(4) Base Revenue	(5) Revenue Difference	(6) Proposed Base Revenues	(7) Percent Change
Uniform Tariff Rates:							
Residential Service	1	13,637	203,752,131	$11,948,371	$262,230	$12,210,601	2.19%
Small General Service	7	2,523	18,036,663	1,219,718	23,214	1,242,932	1.90%
Large Power Service							
Secondary	9S	957	118,308,650	6,547,627	152,264	6,699,891	2.33%
Primary	9P	5	15,996,682	684,741	0	684,741	
Dusk to Dawn Lighting	15	-	443,941	117,996	0	117,996	
Large Power Service	19	8	301,839,827	11,006,504	0	11,006,504	
Irrigation Service							
Secondary	24S	1,442	51,527,180	2,655,758	66,316	2,722,074	2.50%
Unmetered General Service	40	4	26,371	1,629	0	1,629	
Municipal Street Lighting	41	14	869,557	113,782	0	113,782	
Traffic Control Lighting	42	7	18,641	893	0	893	
Total Uniform Tariffs		18,597	710,819,643	$34,297,019	$504,024	$34,801,043	1.47%