McDowell Rackner & Gibson PC

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July 29, 2011

VIA ELECTRONIC FILING
AND HAND DELIVERY

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
550 Capitol Street NE, Suite 215
Salem, OR 97308-2148

Re: Docket No. UE ______
In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Oregon

Enclosed for filing by Idaho Power Company are an original and 30 copies of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Oregon, including the following proposed tariff pages associated with the Company's Tariff P.U.C. ORE No. E-27 applicable to electric service in the State of Oregon, together with the Executive Summary, supporting direct testimony and exhibits. The tariffs reflect an effective date of September 1, 2011.

Sixth Sheet No. 1-2	Cancelling	Fifth Revised Sheet No. 1-2
Second Sheet No. 7-1	Cancelling	First Revised Sheet No. 7-1
Fourth Sheet No. 7-2	Cancelling	Third Revised Sheet No. 7-2
First Revised Sheet No. 9-2	Cancelling	Original Sheet No. 9-2
Fifth Revised Sheet No. 9-3	Cancelling	Fourth Revised Sheet No. 9-3
Fourth Revised Sheet No. 9-4	Cancelling	Third Revised Sheet No. 9-4
Third Revised Sheet No. 15-2	Cancelling	Second Revised Sheet No. 15-2
Fifth Revised Sheet No. 19-3	Cancelling	Fourth Revised Sheet No. 19-3
Fourth Revised Sheet No. 19-4	Cancelling	Third Revised Sheet No. 19-4
Fourth Revised Sheet No. 19-5	Cancelling	Third Revised Sheet No. 19-5
Fifth Revised Sheet No. 24-3	Cancelling	Fourth Revised Sheet No. 24-3
First Revised Sheet No. 40-1	Cancelling	Original Sheet No. 40-1
Sixth Revised Sheet No. 40-2	Cancelling	Fifth Revised Sheet No. 40-2
First Revised Sheet No. 41-1	Cancelling	Original Sheet No. 41-1
Fifth Revised Sheet No. 41-2	Cancelling	Fourth Revised Sheet No. 41-2

Fifth Revised Sheet No. 41-3	Cancelling	Fourth Revised Sheet No. 41-3
Fourth Revised Sheet No. 41-4	Cancelling	Third Revised Sheet No. 41-4
Fifth Revised Sheet No. 42-1	Cancelling	Fourth Revised Sheet No. 42-1

Also enclosed are 3 copies of the CD containing a PDF version of the workpapers and Excel Spreadsheets, where available, corresponding to the pages in the PDF version. The CDs also contain Excel spreadsheets, where available, of the exhibits.

It is respectfully requested that all data requests regarding this matter be addressed to:

Lisa D. Nordstrom
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Boise, ID 83707-0070
Email: lnordstrom@idahopower.com

Christa Bearry
Idaho Power Company
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Idaho Power waives paper service in this docket. Please address all communications related to this filing to:

Lisa D. Nordstrom
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PO Box 70
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Please direct informal correspondence and questions regarding this filing to Lisa Rackner at (503) 595-3925.

Very truly yours,

Lisa Rackner

cc: Citizens' Utility Board of Oregon

TABLE OF CONTENTS
Docket No. UE ____
Oregon 2011 General Rate Case

DOUGLAS N. JONES DIRECT TESTIMONY (EXHIBIT 600)

Exhibit 601	Adjusted Historical Actual Financial Data
Exhibit 602	Deductions from Operations and Maintenance Expenses
Exhibit 603	Specific Rate Base, Revenue, and Expense Adjustments Not Provided Elsewhere

Workpapers

SCOTT WRIGHT DIRECT TESTIMONY (EXHIBIT 700)

Exhibit 701	Power Supply Expenses for 2011 Normalized Loads Over 83 Water Year Conditions
Exhibit 702	2011 October Update

TIMOTHY E. TATUM DIRECT TESTIMONY (EXHIBIT 800)

Exhibit 801	Forecast Methodology Summary
Exhibit 802	Forecast Methodology Manual

KELLEY NOE DIRECT TESTIMONY (EXHIBIT 900)

Exhibit 901	Major Plant Additions Annualized for 2011
Exhibit 902	Depreciation and Amortization Annualizing Adjustments
Exhibit 903	Summary of Payroll-Related Annualizing Adjustments
Exhibit 904	Development of System Revenue Requirement
Exhibit 905	Jurisdictional Separation Study – Oregon Revenue Requirement

Workpapers

MATTHEW T. LARKIN DIRECT TESTIMONY (EXHIBIT 1000)

Exhibit 1001	Development of Sales Forecast for Revenue Calculation
Exhibit 1002	Retail Revenue Forecast Summary
Exhibit 1003	Retail Revenue Forecast Derivation
Exhibit 1004	Revenue Requirement by Functional Category
Exhibit 1005	Marginal Cost Analysis
Exhibit 1006	Summary of Marginal Costs by Customer Class
Exhibit 1007	Revenue Allocation Summary

Workpapers

DARLENE NEMNICH DIRECT TESTIMONY (EXHIBIT 1100)

Exhibit 1101	Calculation of Revenue Impact
Exhibit 1102	Typical Monthly Billing Comparison

Workpapers

SCOTT D. SPARKS DIRECT TESTIMONY (EXHIBIT 1200)

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE_____

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF OREGON.	**IDAHO POWER COMPANY'S EXECUTIVE SUMMARY**

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") is filing a general rate increase with the Public Utility Commission of Oregon ("Commission"), pursuant to ORS 757.205, 757.215 and 757.220, to revise its schedules of rates and charges for electric service in Oregon to become effective with service provided on and after September 1, 2011. With this filing, the Company requests an increase to customer rates that will increase the Company's annual Oregon jurisdictional revenues by $5.8 million, which is 14.7 percent greater than the revenues that could be generated under current rates. The revised rates produce revenues necessary to sustain the provision of stable, reliable, and low-cost electric service to customers in Oregon, while preserving the Company's ability to attract capital for future investments in system infrastructure. The Company files this executive summary in accordance with OAR 860-022-0019.

II. BACKGROUND

Idaho Power is an Idaho corporation whose principal place of business is 1221 West Idaho Street, Boise, Idaho 83702. Idaho Power is an electric company and a public utility providing electric service in Oregon within the meaning of ORS 757.005. The Company is subject to the jurisdiction of this Commission, the Idaho Public Utilities Commission, and the

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Federal Energy Regulatory Commission. The Company provides electric service to approximately 18,453 customers in Oregon and approximately 492,073 total customers in Idaho and Oregon. In conducting its utility business, Idaho Power operates an interconnected and integrated system.

Communications regarding this filing should be addressed to:

Lisa D. Nordstrom Idaho Power Company PO Box 70 Boise, ID 83707-0070 Telephone: 208-388-5825 Facsimile: 208-388-6936 Email: lnordstrom@idahopower.com	Lisa Rackner McDowell Rackner & Gibson PC 419 SW 11th Avenue, Suite 400 Portland, OR 97205 Telephone: 503-595-3925 Facsimile: 503-595-3928 Email: lisa@mcd-law.com
Christa Bearry Idaho Power Company PO Box 70 Boise, ID 83707-0070 Telephone: 208-388-5996 Facsimile: 208-388-6936 Email: cbearry@idahopower.com	

Communications regarding discovery matters, including data requests issued to the Company, should be addressed to:

Lisa D. Nordstrom Idaho Power Company PO Box 70 Boise, ID 83707-0070 Telephone: 208-388-5825 Facsimile: 208-388-6936 Email: lnordstrom@idahopower.com	Lisa Rackner McDowell Rackner & Gibson PC 419 SW 11th Avenue, Suite 400 Portland, OR 97205 Telephone: 503-595-3925 Facsimile: 503-595-3928 Email: lisa@mcd-law.com
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III. CASE SUMMARY

A. The Test Year

The Company's test year in this case is the twelve months ending December 31, 2011 ("2011 Test Year"). Idaho Power provides information for a historical base period of twelve months ending December 31, 2010, and makes adjustments to that information to reflect the forecast 2011 Test Year. In order to meet the legal requirement that rates be fair, just, reasonable, and sufficient, the Company has selected a test year that closely reflects the investment and expense levels that will exist during the time that the rates adopted in this case are expected to be in effect. The new rates are filed with a requested effective date of September 1, 2011. Assuming the addition of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs, the new rates would become effective June 1, 2012.

B. Return on Equity

In the Company's last Oregon general rate case, Docket UE 213, the Commission approved a stipulation that included a return on equity ("ROE") of 10.175 percent. The actual ROE earned by the Company over the last several years has been consistently below that level. Indeed, the average of the Oregon jurisdiction normalized ROE has been 1.17 percent since 2005.

In this case, the Company seeks an ROE of 10.5 percent. This conservative request is necessary to maintain the financial integrity of the Company while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impact. To achieve the 10.5 percent ROE, an Oregon jurisdictional revenue increase of $5.8 million is necessary. The proposed rate increase constitutes an average overall price increase of 14.7 percent in base rates. Even with this requested rate increase, the Company's Oregon customers will continue to benefit from some of the lowest electricity rates in the nation.

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C. Factors Driving Rate Adjustment

1. Investments in Plant to Serve Customers

One of the key factors driving Idaho Power's need for a rate increase is the Company's increasing investment in plant to serve customers. This investment is the result of two factors—continuing customer load growth and the need to refurbish existing transmission, distribution, and generation infrastructure. Indeed, since the Company's last general rate case, it has placed in service over $316 million in gross plant. These investments are necessary to ensure that Idaho Power's infrastructure maintains its operational viability and is able to continue to provide safe, reliable, and efficient energy at reasonable rates.

Although there has been some slowing of the rapid load growth the Company experienced several years ago, Idaho Power is still forecasting consistent load growth going forward. Indeed, the Company expects billed sales to increase an average of three percent over the next three years. The Company also anticipates adding new large loads. New loads totaling approximately 741 megawatts ("MW") have made inquiries to the Company and approximately 20 percent of those inquiries came from the Oregon service area. Overall, the Company expects to add up to 6,000 customers this year.

The Company's transmission investments include the new 500 kilovolt ("kV") Hemingway Transmission Station and the associated Hemingway to Bowmont 230 kV transmission line. The build-out of this critical transmission pathway will relieve transmission constraints and allow the Company to more easily import power to serve Idaho Power's growing customer load. This project, as well as others, has also increased the overall reliability of the Company's transmission network. In total, the Company's transmission line miles increased from 4,752 miles at the end of 2008 to 4,817 miles at the end of 2010.

The Company's investment in distribution plant in this case includes the completed deployment of the Advanced Metering Infrastructure ("AMI") technology in the Company's

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Oregon service area. This deployment involved the installation of 17,500 smart meters and associated station and communication equipment. The Company also used innovative substation upgrade projects to improve the reliability of the distribution system and increased its total distribution line miles from 26,576 miles at the end of 2008 to 26,697 miles at the end of 2010.

In addition to investments in the Company's transmission and distribution network, the costs reflected in this case also include substantial investment in the Company's generating fleet. These investments include upgrades and component replacements to aging hydroelectric and thermal generation facilities. The Company has also invested heavily in pollution control equipment at its Jim Bridger Power Plant. This pollution control equipment was mandated by the Regional Haze Best Available Retrofit Technology ruling from the state of Wyoming. As a result of these investments, the Company's total nameplate generating system capacity increased by 9 MW from 3,267 MW at the end of 2008 to 3,276 MW at the end of 2010.

2. Return on Equity

As previously stated, the Company's request of a 10.5 percent ROE is necessary to maintain the financial integrity of the Company while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impact.

3. Growth in Expenses

Another key factor driving Idaho Power's need for a rate increase is growth in expenses. The Company is experiencing cost increases related to power production, compliance requirements, reliability requirements, materials and supplies, land use fees, maintenance costs and labor costs.

D. Cost Control Efforts

The Company has taken great care to minimize the expenses and investments included in this case to ensure that in these difficult economic times the requested rate

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increase is no greater than necessary. To this end, the Company's filing includes O&M expenses at the 2010 levels with the exception of specific cost categories that are "known" to be materially different in 2011. Moreover, the Company's overall O&M expenses have increased at a rate that is consistently less than the growth in the Consumer Price Index ("CPI") plus the growth in number of customers served expressed as a percentage. The Company's overall O&M expenses also compare favorably relative to other utilities in the western United States.

The Company has also aggressively controlled its labor costs. The Company decreased its headcount by approximately three percent from 2008 to 2010, while total customers served increased one percent over the same time period. And over the last two years of the down economy, the Company has provided for general wage adjustments that are below peer group adjustments to salary structures.

The Company's case also holds normalized total power supply expenses to the currently approved normalized levels determined under the October Update component of the 2011 Annual Power Cost Update. Although the total normalized 2011 power supply expenses is $20.0 million *more* than the currently authorized power supply expense level, the Company is not seeking to include this amount in rates in this case.

With respect to investments in utility plant, the Company regularly and thoroughly analyzes its investment strategy and makes adjustments as necessary to account for the current economic climate. Moreover, the Company has aggressively promoted demand-side management and energy efficiency programs and services in an attempt to reduce the pace of growth in plant investment.

IV. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of twelve witnesses:

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Gregory W. Said, Vice President of Regulatory Affairs, provides a general overview of the case and introduces the Company witnesses and briefly describes their testimony.

Darrel Anderson, Executive Vice President of Administrative Services and Chief Financial Officer, provides an overview of the challenges facing the Company and the need for general rate relief that it is requested in this filing. Mr. Anderson also discusses the increased investment in generation plant, transmission facilities, distribution facilities, and general plant that has been required to provide for the needs of the Company's customers. He describes how reliability requirements, compliance requirements, and the costs of materials and supplies have impacted the level of investments. Finally, Mr. Anderson also addresses Company actions to manage ongoing expenses.

Warren Kline, Vice President of Customer Operations, describes the Company's careful management of costs incurred by the Company to benefit customers. Mr. Kline discusses the changes to the Company's Customer Service Operations organization that result in exemplary customer service and describes the nearing completion of meter replacement with AMI throughout the Company's system. Mr. Kline also discusses the Company's ongoing efforts to pursue all cost-effective energy efficiency

William Avera, President of FINCAP, Inc., testifies concerning the Company's cost of equity. He recommends a fair rate of return on equity range of 10.40 to 11.55 percent. His recommendations are based on his analysis of current capital market estimates using methods such as discounted cash flow analyses, capital asset pricing models, and comparable earnings methodologies. Dr. Avera also discusses flotation costs.

Steven R. Keen, Vice President Finance and Treasurer, builds on Dr. Avera's testimony by presenting the Company recommendation that the Commission authorize an ROE of 10.5 percent, which is at the low end of Dr. Avera's recommended range. Mr. Keen discusses the relevant risk factors impacting the Company and that contributed the

Company's selection of 10.5 percent as the appropriate ROE. Mr. Keen also discusses the cost of debt and overall cost of capital of 8.17 percent.

Douglas N. Jones, Regulatory Accounting and Support Team Leader, presents actual 2010 financial data that serves as the auditable starting point for developing the 2011 Test Year. Mr. Jones then quantifies the adjustments to that financial data that reflect previous Oregon and Idaho Commission directives regarding regulatory treatment of specific accounts.

Scott Wright, Regulatory Analyst, quantifies the 2011 normalized power supply expenses. Because the Company is not seeking recovery of these amounts in this case, Mr. Wright's testimony is informational and demonstrates the Company's desire to mitigate the size of its additional revenue request in this proceeding.

Timothy Tatum, Senior Manager of Cost of Service, provides testimony describing the 2011 Test Year based upon the 2010 actual financial data provided by Mr. Jones. Mr. Tatum also supervised the preparation of the jurisdictional separation study utilized to determine the Oregon jurisdictional revenue requirement.

Kelly Noe, Regulatory Analyst, presents the Oregon jurisdictional revenue requirement which was prepared under the direction of Mr. Tatum.

Matthew T. Larkin, Regulatory Analyst, describes the 2011 Retail Revenue Forecast provided to Ms. Noe for her determination of the Company's revenue deficiency. He also describes the Company's class cost-of-service model that is used in part to determine each customer class's responsibility for a portion of the total Oregon jurisdictional revenue requirement.

Darlene Nemnich, Senior Regulatory Analyst, describes the Company's rate design proposals for residential customers.

Scott Sparks, Senior Regulatory Analyst, describes the Company's rate design proposals for all other customer classes. Mr. Sparks also discusses proposed changes with regard to the Company's facilities charge computations.

V. CONCLUSION

The Company requests that the Commission issue an order approving of the proposed rate changes and approving the proposed tariffs.

DATED: July 29, 2011.

McDowell Rackner & Gibson PC

Lisa F. Rackner
Adam Lowney

Idaho Power Company

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Attorneys for Idaho Power Company

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Jurisdiction
Filed July 29, 2011

Total Revenues Collected Under Proposed Rates:	$ 45,721,401
Revenue Change Requested:	$ 5,847,814
Revenues Net of any Credits from Federal Agencies:	$ 5,847,814
Percentage Change in Revenues Requested:	14.67%
Percentage Change in Revenues Net of any Credits from Federal Agencies:	14.67%
Test Period:	Calendar Year 2011
Requested Rate of Return on Capital:	8.17%
Requested Rate of Return on Equity:	10.50%
Proposed Rate Base:	$ 121,853,764
Results of Operation[1]	
Before Proposed Rate Change	
Utility Operating Income:	$ 7,057,029
Average Rate Base:	$ 114,286,845
Rate of Return on Capital:	6.175%
Rate of Return on Equity:	6.589%
After Proposed Rate Change[2]	
Utility Operating Income:	$ 9,955,453
Average Rate Base:	$ 121,853,764
Rate of Return on Capital:	8.17%
Rate of Return on Equity:	10.50%
Effect of Rate Change on Each Customer Class	
Residential Service:	21.91%
Small General Service:	4.82%
Large General Service, Secondary Voltage:	11.19%
Large General Service, Primary Voltage:	5.32%
Large General Service, Transmission Voltage:	0.00%
Area Lighting Service:	0.00%
Large Power Service, Primary Voltage:	0.00%
Large Power Service, Transmission Voltage:	18.15%
Irrigation Service:	29.34%
Unmetered General Service:	16.60%
Municipal Street Lighting Service:	3.69%
Traffic Control Lighting Service:	29.34%

[1] Based upon the Company's 2010 Report of Operations – JSS – Adj. Type I & II,

[2] Based upon the Company's 2011 general rate case filing.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Proposed Tariffs

July 29, 2011

SCHEDULE 1
RESIDENTIAL SERVICE
(Continued)

RESIDENTIAL SPACE HEATING (Continued)

Individual resistance-type units for space heating larger than 1,650 watts shall be designed to operate at 240 or 208 volts, and no single unit shall be larger than 6 kW. Heating units of two kW or larger shall be controlled by approved thermostatic devices. When a group of heating units, with a total capacity of more than 6 kW, is to be actuated by a single thermostat, the controlling switch shall be so designed that not more than 6 kW can be switched on or off at any one time. Supplemental resistance-type heaters, that may be used with a heat exchanger, shall comply with the specifications listed above for such units.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

Service Charge, per month	$ 10.00		(I)
	Summer	Non-Summer	(C)
Energy Charge, per kWh			
0-1000 kWh	8.2222¢	8.2222¢	(C)(I)
Over 1000 kWh	10.0310¢	9.1266¢	(C)(I)
Power Supply Adjustment, per kWh	0.3507¢		

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served and additional investment by the Company for transmission, substation, or terminal facilities is not necessary to supply the desired service.

APPLICABILITY

Service under this schedule is applicable to Electric Service supplied to a Customer at one Point of Delivery and measured through one meter. This schedule is applicable to Customers whose metered energy usage is 3,000 kWh, or less, per Billing Period for ten or more Billing Periods during the most recent 12 consecutive Billing Periods. When the Customer's Billing Period is less than 27 days or greater than 36 days, the energy usage will be prorated to 30 days for purposes of determining eligibility under this schedule. Customers whose metered energy usage exceeds 3,000 kWh per Billing Period on an actual or prorated basis three times during the most recent 12 consecutive Billing Periods are not eligible for service under this schedule and will be automatically transferred to the applicable schedule effective with the next Billing Period. New customers may initially be placed on this schedule based on estimated usage.

This schedule is also applicable to non-profit or tax supported ball fields, fairgrounds or rodeo grounds with high demands and intermittent use exceeding 3,000 kWh per month. This schedule is not applicable to standby service, service for resale, or shared service, or to individual or multiple family dwellings, or agricultural irrigation service after October 31, 2005.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

SUMMER NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-Summer	
Service Charge, per month			
Single-Phase Service	$ 10.00	$ 10.00	(I)
Three-Phase Service	$ 18.00	$ 18.00	(I)

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

	Summer	Non-Summer	
Energy Charge, per kWh			
0-500 kWh	6.6540¢	6.6540¢	(I)
Over 500 kWh	9.1026¢	7.4155¢	(I)
Power Supply Adjustment, per kWh	0.3507¢	0.3507¢	

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

FACILITIES BEYOND THE POINT OF DELIVERY

At the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Primary or Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company.

Company-owned Facilities Beyond the Point of Delivery will be set forth in a Distribution Facilities Investment Report provided to the Customer. As the company's investment in Facilities Beyond the Point of Delivery changes in order to provide the Customer's service requirements, the Company shall notify the Customer of the additions and/or deletions of facilities by forwarding to the Customer a revised Distribution Facilities Investment Report.

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total depreciated costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

POWER FACTOR ADJUSTMENT (N)

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

TIME PERIODS

The time periods are defined as follows. All times are stated in Mountain Time.

Summer Season	
On-Peak	1:00 p.m. to 9:00 p.m. Monday through Friday, except holidays
Mid-Peak	7:00 a.m. to 1:00 p.m. and 9:00 p.m. to 11:00 p.m. Monday through Friday, except holidays, and 7:00 a.m. to 11:00 p.m. Saturday and Sunday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Sunday and all hours on holidays
Non-Summer Season	
Mid-Peak	7:00 a.m. to 11:00 p.m., Monday through Saturday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Saturday and all hours on Sunday and holidays

The holidays observed by the Company are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. When New Year's Day, Independence Day, or Christmas Day falls on a Sunday, the Monday immediately following that Sunday will be considered a holiday.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	Summer	Non-Summer	
Service Charge, per month			
Single Phase Service	$ 11.00	$ 11.00	(I)
Three Phase Service	$ 19.00	$ 19.00	(I)
Basic Charge, per kW of Basic Load Capacity	$ 0.75	$ 0.75	(I)
Demand Charge, per kW of Billing Demand	$ 6.03	$ 4.53	(I)
Energy Charge, per kWh	5.0845¢	4.6658¢	(I)
Power Supply Adjustment, per kWh	0.3507¢	0.3507¢	

Facilities Charge
None

PRIMARY SERVICE	Summer	Non-Summer	
Service Charge, per month	$207.00	$207.00	(I)
Basic Charge, per kW of Basic Load Capacity	$ 1.17	$ 1.17	(I)
Demand Charge, per kW of Billing Demand	$ 5.61	$ 4.58	(I)
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$ 0.82	n/a	(I)
Energy Charge, per kWh			
On-Peak	4.6211¢	n/a	(I)
Mid-Peak	4.3226¢	3.9061¢	(I)
Off-Peak	4.1279¢	3.7814¢	(I)
Power Supply Adjustment	0.3507¢	0.3507¢	

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent. (R)

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE	Summer	Non-Summer	
Service Charge, per month	\$200.00	\$200.00	
Basic Charge, per kW of Basic Load Capacity	\$ 0.30	\$ 0.30	
Demand Charge, per kW of Billing Demand	\$ 3.59	\$ 3.84	
On-Peak Demand Charge, per kW of On-Peak Billing Demand	\$ 0.69	n/a	
Energy Charge, per kWh			
On-Peak	4.2176¢	n/a	(I)
Mid-Peak	3.9483¢	3.5631¢	(I)
Off-Peak	3.7722¢	3.4507¢	(I)
Power Supply Adjustment	0.3507¢	0.3507¢	

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent. (R)

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the per Unit Charge and the Power Supply Adjustment at the following charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

1. Monthly Per Unit Charge on existing facilities:

AREA LIGHTING

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment	
100 Watt	8,550	$ 10.37	$ 0.14	(I)
200 Watt	19,800	$ 12.40	$ 0.26	(R)
400 Watt	45,000	$ 16.96	$ 0.55	(R)

FLOOD LIGHTING

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment	
200 Watt	19,800	$ 15.00	$ 0.26	(R)
400 Watt	45,000	$ 17.77	$ 0.55	(R)
Metal Halide				
400 Watt	28,800	$ 16.26	$ 0.54	(R)
1,000 Watt	88,000	$ 26.07	$ 1.27	(R)

2. For New Facilities Installed Before August 8, 2005. The Monthly Charge for New Facilities installed, prior to August 8, 2005 such as overhead secondary conductor, poles, anchors, etc., shall be 1.51 percent of the estimated installed cost thereof. (R)

3. For New Facilities Installed On or After August 8, 2005. The non-refundable charge for New Facilities to be installed, such as underground service, overhead secondary conductor, poles, anchors, etc., shall be equal to the work order cost.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

TEMPORARY SUSPENSION

When a Customer has properly invoked Rule G, Temporary Suspension of Demand, the Basic Load Capacity, the Billing Demand, and the On-Peak Billing Demand shall be prorated based on the period of such suspension in accordance with Rule G. In the event the Customer's metered demand is less than 1,000 kW during the period of such suspension, the Basic Load Capacity and Billing Demand will be set equal to 1,000 kW for purposes of determining the Customer's monthly Minimum Charge.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	Summer	Non-Summer	
Service Charge, per month	$222.00	$222.00	(I)
Basic Charge, per kW of Basic Load Capacity	$ 0.56	$ 0.56	(I)
Demand Charge, per kW of Billing Demand	$ 4.68	$ 4.58	(I)
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$ 0.77	n/a	(I)
Energy Charge, per kWh			
On-Peak	5.6689¢	n/a	(I)
Mid-Peak	4.4634¢	4.2133¢	(I)
Off-Peak	3.9425¢	3.8114¢	(I)
Power Supply Adjustment*, per kWh	0.3507¢	0.3507¢	

*Note: A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
None

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

PRIMARY SERVICE	Summer	Non-Summer
Service Charge, per month	$200.00	$200.00
Basic Charge, per kW of Basic Load Capacity	$ 0.97	$ 0.97
Demand Charge, per kW of Billing Demand	$ 4.70	$ 4.35
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$ 0.69	n/a
Energy Charge, per kWh		
On-Peak	4.7848¢	n/a
Mid-Peak	3.7752¢	3.5658¢
Off-Peak	3.3390¢	3.2292¢
Power Supply Adjustment*, per kWh	0.3507¢	0.3507¢

*Note: A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent. (R)

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE	Summer	Non-Summer	
Service Charge, per month	$237.00	$237.00	(I)
Basic Charge, per kW of Basic Load Capacity	$ 0.34	$ 0.34	(I)
Demand Charge, per kW of Billing Demand	$ 4.98	$ 4.71	(I)
On-Peak Demand Charge, per kW of On-Peak Demand	$ 0.96	n/a	(I)
Energy Charge, per kWh			
On-Peak	5.0816¢	n/a	(I)
Mid-Peak	4.0434¢	3.8230¢	(I)
Off-Peak	3.5925¢	3.4760¢	(I)
Power Supply Adjustment*, per kWh	0.3507¢	0.3507¢	

*Note: A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent. (R)

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	In-Season	Out-of-Season	
Service Charge, per month	$ 22.00	$ 3.50	(I)
Demand Charge, per kW of Billing Demand	$ 9.00	$ 0.00	(I)
Energy Charge, per kWh			
In Season			
First 164 kWh per kW of Demand	7.2459¢	n/a	(I)
All Other kWh	6.8358¢	n/a	(I)
Out-of-Season			
All kWh	n/a	7.6079¢	(I)
Power Supply Adjustment, per kWh	0.3507¢	0.3507¢	

Facilities Charge
None

TRANSMISSION SERVICE	In-Season	Out-of-Season	
Service Charge, per month	$188.00	$ 3.50	(I)
Demand Charge, per kW of Billing Demand	$ 8.48	$ 0.00	(I)
Energy Charge, per kWh			
In Season			
First 164 kWh per kW of Demand	7.0157¢	n/a	(I)
All Other kWh	6.6200¢	n/a	(I)
Out-of-Season			
All kWh	n/a	7.3629¢	(I)
Power Supply Adjustment, per kWh	0.3507¢	0.3507¢	

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent.

SCHEDULE 40
NONMETERED GENERAL SERVICE (T)

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing secondary distribution facilities of adequate capacity, phase and voltage are available adjacent to the Customer's Premises and the only investment required by the Company is an overhead service drop.

APPLICABILITY

Service under this schedule applies to Electric Service for the Customer's single- or multiple-unit loads up to 1,800 watts per unit where the size of the load and period of operation are fixed and, as a result, actual usage can be accurately determined. Service may include, but is not limited to, security lighting, telephone booths and (D) CATV power supplies which serve line amplifiers. Equipment or loads constructed or operated in such a way as to allow for the potential or actual variation in energy use are not eligible for service under this schedule. Facilities to supply service under this schedule shall be installed so that service cannot be extended to the Customer's loads served under other schedules. Service under this schedule is not applicable to shared or temporary service, or to the Customer's loads on Premises which have metered service.

SPECIAL TERMS AND CONDITIONS

The Customer shall pay for all Company investment, except the overhead service drop, required to provide service requested by the Customer. The Customer is responsible for installing, owning and maintaining all equipment, including necessary underground circuitry and related facilities to connect with the Company's facilities at the Company designated Point of Delivery. If the Customer's equipment is not properly maintained, service to the specific equipment will be terminated.

Energy used by CATV power supplies which serve line amplifiers will be determined by the power supply manufacturer's nameplate input rating assuming continuous operation.

The Customer is responsible for notifying the Company of any changes or additions to the equipment or loads being served under this schedule. Failure to notify the Company of such changes or additions will result in the termination of service under this schedule and the requirement that service be provided under one of the Company's metered service schedules.

If the Customer modifies existing equipment being served under this schedule in a way that allows for the potential or actual variation in energy usage or installs additional equipment that allows for the potential or actual variation in energy usage, service under this schedule will be terminated and the Customer will be required to receive service under one of the Company's metered service schedules.

With Company approval, municipalities or agencies of federal, state, or county governments may install equipment that allows for the potential intermittent variation in energy usage at authorized Points of Delivery. Under these circumstances, the Customer's bill will include fixed units of the Intermittent Usage Charge in addition to the Customer's other Monthly Charges.

The Company is only responsible for supplying energy to the Point of Delivery and, at its expense, may check energy consumption at any time.

SCHEDULE 40
UNMETERED GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is nonmetered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions). (T)

Energy Charge, per kWh	8.774¢	(I)
Power Supply Adjustment, per kWh	0.3507¢	
Minimum Charge, per month	$ 1.50	

ADDITIONAL CHARGES

Applicable only to municipalities or agencies of federal, state, or county governments with an authorized Point of Delivery having the potential of intermittent variations in energy usage.

Intermittent Usage Charge, per unit, per month	$ 1.00

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Oregon where
street lighting wires and fixtures can be installed on Customer-provided street lighting facilities or installed on the (N)
Company's existing distribution facilities.

APPLICABILITY

Service under this schedule is applicable to service requested or installed by Customers for the lighting of public (C)
streets, public alleys, public grounds, and thoroughfares. Street lighting lamps will be energized each night from (C)
dusk until dawn.

SERVICE LOCATION AND PERIOD

Street lighting facility locations, type of unit and lamp sizes, as changed from time to time by written request of the
Customer and agreed to by the Company, shall be provided for Customers receiving service under Options A and (N)
B of this schedule. The in-service date for each street lighting facility shall also be maintained. (N)

The minimum service period for any Company-owned street lighting facility is 10 years. The Company, upon (N)
written notification from the Customer, will remove a Company-owned street lighting facility: (N)

1. At no cost to the Customer, if such facility has been in service for no less than the minimum service
period. The Company will not grant a request from the Customer for reinstallation of street lighting
service at the same location for a minimum period of two years from the date of removal. (N)

2. Upon payment to the Company of the removal cost, if such facility has been in service for less than the minimum service period.

SERVICE OPTIONS (N)

"A" - Idaho Power-Owned, Idaho Power-Maintained System (C)

The facilities required for supplying service, including fixture, lamp, control relay, mast arm for mounting on an existing utility pole, and energy for the operation thereof, are supplied, installed, owned and maintained by the Company. All necessary repairs and maintenance work, including group lamp replacement and glassware cleaning, will be performed by the Company during the regularly scheduled working hours of the Company on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

The Company has two standard street lighting fixture options, drop-glass or cut-off (shielded lighting). For each initial lighting fixture installation, the Customer is required to state, in writing, a fixture preference. A maintenance-related replacement of a current fixture will be made with a similar type of drop-glass or cut-off fixture as the one being replaced unless written notification has been received from the Customer requesting a change in fixture types.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS (Continued)

"A" - Idaho Power-Owned, Idaho Power-Maintained System (Continued)

Accelerated Replacement of Existing Fixtures

In the event a Customer requests the Company perform an accelerated replacement of existing fixtures with the cut-off fixture, the following charges will apply:

1. The designed cost estimate which includes labor, time, and mileage costs for the removal of the existing street lighting fixtures.

2. $132.00 per fixture removed from service. (I)

The total charges identified in 1 and 2 above must be paid prior to the beginning of the fixture replacement and are non-refundable. The accelerated replacement will be performed by the Company during the regularly scheduled working hours of the Company and on the Company's schedule.

Monthly Charges

The Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Lamp Charges, per lamp (41A) (N)

Standard High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment	(N)
70 Watt	5,540	$ 9.83	$ 0.10	(R)
100 Watt	8,550	$ 8.50	$ 0.14	(I)
200 Watt	19,800	$ 11.47	$ 0.26	|
250 Watt	24,750	$ 12.53	$ 0.35	|
400 Watt	45,000	$ 14.33	$ 0.55	(I)

Pole Charges

For Company-owned poles required to be used for street lighting only:

Wood pole	$ 1.90 per pole
Steel pole	$ 7.39 per pole

Facilities Charge

Customers assessed a monthly facilities charge prior to August 8, 2005 for the installation of underground circuits will continue to be assessed a monthly facilities charge equal to 1.21 percent of the estimated cost difference between overhead and underground circuits. (R)

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS(Continued)

"A" - Idaho Power-Owned, Idaho Power-Maintained System (Continued)

Monthly Charges (Continued)

Payment (N)

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered. (N) (N)

"B" - Customer-Owned, Idaho Power-Maintained System – No New Service (N)

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer and maintained by Idaho Power. Customer-owned lighting systems receiving maintenance under Option B must have Idaho Power standard wattage high pressure sodium vapor lamps installed in all street lighting fixtures. (N) (N) (N)

Customer-owned systems constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage, such as through, but not limited to, the use of wired outlets or useable plug-ins, are required to be metered in order to record actual energy usage.

Energy and Maintenance Service

Energy and Maintenance Service includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective photocells which are standard to the Company-owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, painting, or refinishing of metal poles. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

(D)

Monthly Charges

The Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Non-Metered Service, per lamp (41B) (C)

Standard High Pressure Sodium Vapor Energy and Maintenance Charges	Average Lumens	Monthly Base Rate	Power Supply Adjustment	(N) (N)
70 Watt	5,540	$ 2.42	$ 0.10	(R)
100 Watt	8,550	$ 2.47	$ 0.14	|
200 Watt	19,800	$ 3.71	$ 0.26	|
250 Watt	24,750	$ 4.65	$ 0.35	|
400 Watt	45,000	$ 6.70	$ 0.55	(R)

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

(D)

Payment

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

"C" - Customer-Owned, Customer-Maintained System (N)

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed, owned, and maintained by the Customer. The Customer is responsible for notifying the Company of any changes or additions to the lighting equipment or loads being served under Option C – Non-Metered Service. Failure to notify the Company of such changes or additions will result in the termination of non-metered service under Option C and the requirement that service be provided under Option C - Metered Service.

All new Customer-owned lighting systems installed outside of Subdivisions on or after January 1, 2012 are required to be metered in order to record actual energy usage.

Customer-owned systems installed prior to June 1, 2004 that are constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage may have the estimated annual variations in energy usage charged the Non-Metered Service - Energy Charge until the street lighting system is converted to Metered Service, or until the potential for variations in energy usage has been eliminated, whichever is sooner.

Monthly Charges

The monthly charges are as follows, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). For non-metered service, the average monthly kWh of energy usage shall be estimated by the Company based on the total wattage of the Customer's lighting system and 4,059 hours of operation.

Non-Metered Service (41C)

Energy Charge, per kWh	3.5865¢

Metered Service (41CM)

Service Charge, per meter	$2.90
Energy Charge, per kWh	3.5865¢

(N)

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Oregon. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

CHARACTER OF SERVICE

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

The installation of a meter to record actual energy consumption is required for all new traffic control signal lighting systems installed on or after August 8, 2005. For traffic control signal lighting systems installed prior to August 8, 2005 a meter may be installed to record actual usage upon the mutual consent of the Customer and the Company.

MONTHLY CHARGE

The monthly kWh of energy usage shall be either the amount estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated, or the actual meter reading as applicable. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Energy Charge, per kWh	9.750¢	(I)
Power Supply Adjustment, per kWh	0.3507¢	

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

EFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GREGORY W. SAID

July 29, 2011

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 ("Idaho Power" or "Company") as the Vice President of Regulatory Affairs.

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 and am now on the faculty of that program covering "Regulation and Ratemaking." I have attended numerous additional educational conferences throughout my career at Idaho Power and am an active member of the Edison Electric Institute's Rates and Regulatory Affairs Committee.

Q. Please describe your work experience with Idaho Power.

A. I was hired by Idaho Power 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 Idaho Public Utilities Commission established the PCA as an annual adjustment to the Company's rates. The Company now has a power cost adjustment mechanism in Oregon as well, which resulted from years of discussion with Oregon Staff and the parties prior to the Public Utility Commission of Oregon's ("Commission") approval. I was involved in those discussions.

In 1996, I was promoted to Director of Revenue Requirement. I managed the preparation of revenue requirement information for regulatory proceedings until 2008.

In 2008, I was promoted to Director of State Regulation, overseeing the management of both cost-of-service and rate design.

In 2010, I was promoted to General Manager of the Regulatory Affairs Department and, in 2011, I was promoted to Vice President of Regulatory Affairs.

As the Vice President of Regulatory Affairs, I oversee and direct the activities of the Regulatory Affairs Department. These activities include the development of jurisdictional revenue requirements, the oversight of the Company's rate adjustment mechanisms, the preparation of cost-of-service studies, the preparation of rate design analyses, and the administration of tariffs and customer contracts. I also have the primary responsibility for corporate policy regarding matters related to the economic regulation of Idaho Power. I have submitted testimony to the Commission on numerous occasions.

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

A. First and foremost, the purpose of my testimony is to present the Company's request that the Commission grant Idaho Power a 5.8 million increase to Oregon jurisdictional revenues, which is 14.6 percent greater than the revenues that could be generated under current rates.

As the Vice President of Regulatory Affairs, I am responsible for the overall preparation and presentation of this filing. I will provide an overview of the Company's case and summarize what I consider to be the major points contained in the testimony of the various Company witnesses.

I. BACKGROUND

Q. When did the Company last receive general rate relief in Oregon?

A. The Company received a 15.4 percent general rate increase on March 1, 2010. The increase was approved by the Commission based upon settlement by the parties in Docket No. UE 213; it reflected a 2009 test year with a 10.175 percent return on equity.

Q. What test year is the Company proposing in this case?

A. The Company is proposing a 2011 test year ("2011 Test Year", or "Test Year."). Consistent with the Company's test year approach in its last general rate case, UE 213, the Company is recommending a test year that is in progress at the time of filing, but will have ended prior to the time that new rates take effect in January 2012. Because the actual test year information is not known at the time of case preparation, the Company makes adjustments to 2010 actual data in order to reflect ratebase, revenues and expenses for the Test Year.

Q. What return on equity does the Company propose be approved by the Commission in this case?

A. The Company recommends that the Commission approve a 10.5 percent return on equity for Idaho Power in this case.

II. CASE STRUCTURE AND WITNESS SUMMARY

Q. Please provide a summary of the financial factors driving the need for rate relief as detailed in the testimony of Mr. Darrel Anderson, Executive Vice President of Administration and Chief Financial Officer.

A. Mr. Anderson discusses numerous financial challenges facing the Company, such as a down economy coupled with rising costs and constrained capacity issues. He describes the Company's increased investment in generation plant, transmission facilities, distribution facilities, and general plant that has been required to provide for the needs of the Company's customers. He describes how reliability requirements, compliance requirements, and the costs of materials and supplies have impacted the level of investment.

Mr. Anderson also addresses the actions taken by the Company to manage ongoing expenses. Specifically, he points out that over the last two years of the down economy, the Company has provided for general wage adjustments that are below peer group adjustments to salary structures. While the Company does not fear losing employees in the short-term, in the longer term, the Company will need to return to its strategy of setting and maintaining a salary structure that allows employees the opportunity to receive the median level compensation for like jobs at other companies.

Q. Does Mr. Anderson discuss the Company's opportunity to earn its authorized rate of return given the additional investments and ongoing expenses of the Company?

A. Yes. Mr. Anderson notes that the Company has not earned its authorized rate of return in any of the last five years and does not expect to earn its authorized rate of return in 2011 --absent a positive determination from the Internal Revenue Service related to the Company's request to change tax methods related to uniform capitalization for income taxes.

Q. Given the Company's need for rate relief as described by Mr. Anderson, did he give you any specific instructions with regard to preparation of this case?

A. Yes. While Mr. Anderson is fully aware that the Company has not earned its authorized rate of return in any of the last five years, he is also cognizant of the prolonged economic downturn. As a result, Mr. Anderson instructed me to identify areas where the Company could forego requesting an increase at this time and keep the Company's requested rate increase as small as possible. Toward that end, I recommended to Mr. Anderson that the Company (a) request operation and maintenance expenses equal to 2010 levels with the exception of specific cost categories that are "known" to be materially different in 2011; and (b) forego requesting incremental power supply expenses as part of this filing.

Q. Please provide your rationale for this recommendation.

A. Idaho Power recognizes the importance of managing its costs at all times, especially during difficult economic times. By limiting the Company's current request to 2010 expense levels with only known material changes, the Company is demonstrating its commitment to manage expenses. With regard to incremental power supply expenses, the Commission has recently approved the Company's annual power cost adjustment ("APCU") rate change request, UE 222, Order No. 11-178, and the Company will file for new APCU rates before rates from this case are likely to be determined. New rates should be in effect simultaneously with the filing of this case and reflect then current power expense levels. Any changes in power supply expenses that occur next year will, to a large extent, be reflected at mid-year 2012, at the time of the next APCU rate change. Depending on a number of factors, that APCU rate can either go up or down.

Q. Please summarize the purpose of Mr. Warren Kline's testimony in this case.

A. Mr. Kline is the Company's Vice President of Customer Operations. Mr. Kline describes the Company's efforts to manage costs in order to benefit customers.

Specifically, Mr. Kline discusses changes to the Company's Customer Service Operations organization that result in exemplary customer service. For example, he describes how Mobile Workforce Management has been utilized to optimize daily field processes.

Mr. Kline goes on to describe the nearing completion of meter replacement with Advanced Metering Infrastructure ("AMI") throughout the Company's system. Meter replacement in the Oregon jurisdiction was completed in 2010. Mr. Kline describes how the Company was able to leverage its meter change-outs to receive a Smart Grid Investment Grant from the U.S. Department of Energy, which will provide for up to $47 million of infrastructure that will be treated as a Contribution in Aid of Construction benefitting customers.

Mr. Kline also describes the Company's ongoing efforts to pursue all cost-effective energy efficiency.

Finally, Mr. Kline explains how all of the efforts he has discussed have been reflected in customer satisfaction measurements. In particular, Mr. Kline explains that customer satisfaction is significantly higher than when the Company began such measurements in 1995 and that the Company has had consistently high performance in recent years.

Q. Did the Company hire an outside consultant to evaluate and determine an appropriate acceptable range in which the Company's authorized rate of return on equity ("ROE") should be set?

A. Yes. Dr. William E. Avera has been the Company's consultant on this issue for many years.

Q. What does Dr. Avera recommend as the range in which Idaho Power's authorized ROE should be set?

A. Dr. Avera provides detailed testimony regarding his analyses of Idaho Power and the utility industry in general. He describes his capital market estimates based upon methods such as discounted cash flow analyses, capital asset pricing models, and comparable earnings methodologies. He also discusses flotation costs. Given the full body of his analyses, Dr. Avera recommends a fair rate of return on equity range of 10.40 to 11.55 percent.

Q. Please describe how Mr. Steven R. Keen, Vice President, Finance and Treasurer, used Dr. Avera's recommended fair rate of return on equity range to arrive at the point estimate for ROE that the Company recommends be approved as the authorized rate of return on equity in this case.

A. Mr. Keen presents the Company request that the Commission authorize an ROE of 10.5 percent for the purposes of determining the Company's jurisdictional revenue requirement in this case. This requested ROE is near the bottom of Dr. Avera's recommended range. It is above the currently authorized rate of return on equity in Oregon, but equal to the currently authorized rate of return on equity in Idaho Power's Idaho jurisdiction.

In arriving at his point estimate, Mr. Keen discusses the need for an ROE that is adequate to attract capital in today's financial markets. He discusses the following risk factors facing the Company that have been identified by those markets:

1. Declining credit ratings;
2. Actual results compared to authorized ROE;
3. Power cost volatility;
4. Hells Canyon relicensing;
5. Impacts of purchases of energy from Qualifying Facilities; and
6. Required reliability investments.

Q. Does Mr. Keen propose a cost of debt to be used in determining the Company's Idaho jurisdictional revenue requirement?

A. Yes. Mr. Keen recommends a cost of debt of 5.728 percent.

Q. What is the overall cost of capital as quantified by Mr. Keen, incorporating the recommended 10.5 percent ROE and 5.728 percent cost of debt?

A. Mr. Keen has quantified the overall cost of capital to be 8.17 percent.

Q. Who is the next witness in the Company's presentation of its case in this proceeding?

A. Following Mr. Keen in the presentation of the Company's case is Mr. Douglas N. Jones, Regulatory Accounting and Support Team Leader. Mr. Jones presents actual 2010 financial data as reported to the Securities and Exchange Commission in the Company's Form 10-K and to the Federal Energy Regulatory Commission ("FERC") in the Company's FERC Form 1. This data serves as the auditable starting point for development of the 2011 Test Year.

Q. Does Mr. Jones perform another function in the preparation of the Company's case?

A. Yes. In addition to providing the Company's actual financial data for the 2010 auditable starting point, Mr. Jones quantifies the adjustments to that financial data that reflect previous Oregon and Idaho Commission directives regarding regulatory treatment of specific accounts.

Q. Please describe the Company's quantification of 2011 normalized power supply expenses.

A. Mr. Timothy E. Tatum, Senior Manager of Cost of Service, requested that Mr. Scott Wright, Regulatory Analyst II, quantify 2011 normalized power supply expenses using the AURORA model that has been routinely utilized for ratemaking determination by this Commission for a number of years.

Mr. Wright has quantified 2011 Test Year normalized net power supply expenses to be $267.5 million.

Q. How does this number compare to the currently authorized total power supply expense?

A. Mr. Wright's quantification of total normalized 2011 power supply expenses at $267.5 million is $20.0 million more than the currently authorized power supply expense level of $247.5 million. As I previously stated, the Company is not requesting the estimated $20.0 million increase in net power supply expenses in this case. Mr. Wright's testimony is informational and demonstrates the Company's desire to mitigate the size of its additional revenue request in this proceeding.

Q. Please describe the instructions you gave to Mr. Tatum regarding preparation of the 2011 t=Test Year in this case.

A. I instructed Mr. Tatum to prepare the 2011 Test Year based upon the 2010 actual financial data provided by Mr. Jones in a manner similar to that accepted by the Commission in UE 213. However, I instructed Mr. Tatum to deviate from that approach in specific areas.

I told Mr. Tatum to hold operations and maintenance ("O&M") expenses to 2010 levels with the exception of specific cost categories that are "known" to be materially different in 2011. I told Mr. Tatum to hold normalized total power supply expenses and related APCU accounts to 2010 levels as approved in Commission Order No. 11-178. I have previously discussed the Company's rationale for such instructions.

Q. Given your instructions to Mr. Tatum, please describe how Mr. Tatum's testimony fits into the Company's presentation of its case.

A. Mr. Tatum describes how the Company utilized the 2010 financial data as presented by Mr. Jones as a starting point from which he made conservative adjustments to derive similar data corresponding to the 2011 Test Year. Mr. Tatum prepared Exhibit 802 that details the method and rationale for each adjustment he utilized in developing the 2011 Test Year data. Once he determined the 2011 Test Year system-level data, Mr. Tatum supervised the preparation of the jurisdictional separation study utilized to determine the Idaho jurisdictional revenue requirement. (Exhibit 905.)

Q. Who is the Company witness that quantified the Oregon jurisdictional revenue requirement?

A. Ms. Kelley Noe, Regulatory Analyst II, prepared the Oregon jurisdictional revenue requirement under the direction of Mr. Tatum. Ms. Noe describes her preparation of the jurisdictional separation study incorporating Mr. Keen's return recommendations and Mr. Tatum's recommended adjustments to the financial data presented by Mr. Jones. She then describes the methods by which each regulatory account is allocated to either the Oregon or Idaho jurisdiction. As noted in Mr. Tatum's testimony, the resulting Oregon jurisdictional revenue requirement as quantified by Ms. Noe is $45.7 million and the current Oregon jurisdictional revenue deficiency also quantified by Ms. Noe is $5.8 million.

Q. Please describe the next area of presentation in the Company's case.

A. Mr. Matthew T. Larkin, Regulatory Analyst I, describes the 2011 Retail Revenue Forecast provided to Ms. Noe for her determination of the Company's revenue deficiency. He also describes the Company's class cost-of-service model that is used in part to determine each customer class's responsibility for a portion of the total Oregon jurisdictional revenue requirement.

Q. Is the Company proposing to establish rates for its Oregon jurisdictional customer classes that will move each customer class to its class cost-of-service?

A. No. Mr. Larkin has prepared Exhibit 1007 that shows the percentage of rate change that would be required in order to move each customer class to its cost-of-service. After discussions with Mr. Larkin, Mr. Tatum, and Mr. Michael J. Youngblood, Manager of Rate Design, I instructed Mr. Larkin to provide the Rate Design Team with class revenue targets that would not decrease any customer class rate, would cap any customer class rate at two times the system average rate increase, and would reallocate any shortfall in revenue collection created by capping increases to classes receiving uncapped increases.

Q. Please describe the testimony of Company witnesses Ms. Darlene Nemnich, Senior Regulatory Analyst, and Mr. Scott Sparks, Senior Regulatory Analyst.

A. Ms. Nemnich describes the Company's rate design proposals for residential customers and Mr. Sparks describes the Company's rate design proposals for all other customer classes. Mr. Sparks also discusses proposed changes with regard to the Company's facilities charge computations.

Q. What are the Company's overall objectives with regard to its rate design strategy?

A. The Company's rate designs are developed to recover the revenue requirement targets provided by Mr. Larkin for each customer class. However, in doing so, the Company continues to maintain two primary objectives with regard to rate design: (1) to establish prices that primarily reflect the costs of the services provided and (2) to have cost-based rate proposals designed to align with and encourage energy efficiency.

Q. Please describe your instructions to Ms. Nemnich and Mr. Sparks.

A. I instructed Ms. Nemnich and Mr. Sparks to continue the Company practice of recommending moderate movement of billing determinant rate components toward cost-of-service levels. Further, I instructed Ms. Nemnich and Mr. Sparks to look for opportunities to incorporate rate designs that will encourage customers to use energy more efficiently.

III. CASE SUMMARY

Q. Please summarize the Company's requested rate relief in this case.

A. Using 2011 test year financial information, the Company has determined its Oregon jurisdictional revenue requirement to be $45.7 million, resulting in an annual revenue deficiency of $5.8 million. An increase to annual Oregon jurisdictional revenues in the amount of $5.8 million would result in an average increase to customer rates of 14.7 percent. The presented case demonstrates that Idaho Power has been prudent in the management of its operations and finances and has diligently looked for opportunities to mitigate its requested rate increase where practicable. The Company believes that the requested rate relief would provide the minimum level of revenue needed to provide Idaho Power with a reasonable opportunity to earn the requested rate of return.

Q. Please detail the specific approval the Company is requesting from the Commission.

A. The Company requests specific Commission approval of the following:

1. A current Oregon jurisdictional revenue requirement of $45.72 million, as quantified by Ms. Noe;
2. An authorized ROE of 10.5 percent, as recommended by Mr. Keen;
3. An authorized overall rate of return of 8.17 percent, as recommended by Mr. Keen;
4. An overall increase in revenues of $5.8 million to eliminate the current Oregon revenue deficiency, as quantified by Ms. Noe;
5. Class revenue requirements, as determined by Mr. Larkin; and
6. Rate designs as proposed by Ms. Nemnich and Mr. Sparks.

The Company believes that these determinations can reasonably be made based upon the full and detailed testimony provided by the Company in this case.

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

A. Yes. The proposed rates are in the public interest because they will allow Idaho Power to continue providing safe, reliable service at reasonable rates while maintaining its financial health.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DARREL ANDERSON

July 29, 2011

Q. Please state your name and business address.

A. My name is Darrel Anderson 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 ("Idaho Power" or "Company") as the Executive Vice President of Administrative Services and Chief Financial Officer.

Q. Please describe your educational background.

A. In 1979, I graduated from Oregon State University with a Bachelor of Science Degree in Accounting and Finance. I am a licensed Certified Public Accountant in the state of Oregon (#4312 inactive). In 2005, I completed the Advanced Management Program at the Harvard Graduate School of Business.

Q. Please describe your work experience prior to joining Idaho Power.

A. Before joining Idaho Power in 1996, I was the Chief Financial Officer of Sisters of Saint Mary of Oregon. Prior to joining the Sisters of Saint Mary of Oregon, I was a senior manager of Audit Services for Deloitte & Touche and was a firm-designated specialist in electric and gas utility operations. I was employed at Deloitte & Touche from 1979 until 1995.

Q. Please describe your work experience with Idaho Power and IDACORP, Inc. ("IDACORP").

A. I joined Idaho Power in 1996 as a Controller in the Finance Department. In 1998, I served as Executive Vice President of Finance and Operations at Applied Power Corporation, a subsidiary of IDACORP. In April 1999, I became Idaho Power's Vice President of Finance and Treasurer. From July 2004 to September 2009, I served as the Company's Senior Vice President of Administrative Services and Chief Financial Officer and was responsible for all financial and treasury functions as well as certain corporate functions that support the operations of the utility business.

These functions include inventory management, procurement, human resources, information technology, facilities, and communications. Since being appointed Idaho Power and IDACORP's Executive Vice President of Administrative Services in October 2009, I continue to oversee Finance, Treasury, and Administrative Services.

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

A. My testimony will provide an overview of challenges facing the Company and the need for general rate relief that is requested in this filing. I will describe the growth in investment and expenses since the Company's last general rate case. In addition, I will describe the reasons why utility costs are increasing and discuss how Idaho Power is prudently managing those cost increases. Lastly, I will discuss the Company's earnings performance since 2008 and explain that the Company has not earned its authorized return on equity ("ROE") for more than five years and does not expect to do so in 2011, unless the Company is successful in its effort to sustain a positive determination from the Internal Revenue Service regarding its request to change tax methods related to uniform capitalization for income taxes. The chart below shows Idaho Power's system-wide annual actual ROE and its Oregon jurisdiction normalized ROE (which is what is used for the Oregon earnings test) compared to its authorized ROE over the last six years. As depicted below and in Exhibit 201, the average of the Oregon jurisdiction normalized ROE has been 1.17 percent since 2005.

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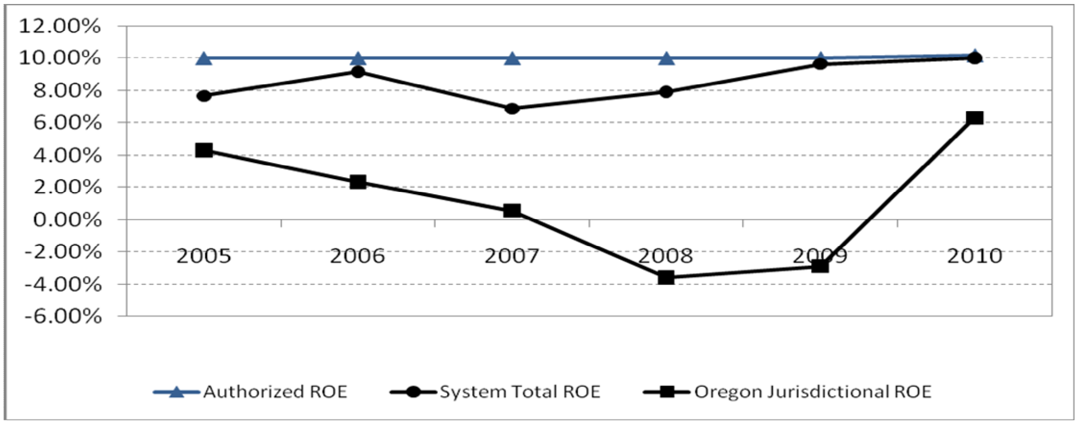


Q. Are you the witness that can address overall Company policy?

A. Yes.

Q. What are the challenges facing the Company?

A. Rising prices and costs, constrained capacity, and the uncertain impacts of climate change legislation are challenges facing utilities across the nation, and Idaho Power is no different. Despite considerable investment and expansion in recent years, much of the Company's system is currently fully utilized. To provide safe, reliable service to all customers, the Company must continue to make major investments in both new and existing infrastructure. Worldwide demand for the materials and services required to build needed infrastructure has driven up prices dramatically over the last several years. Climate change concerns require selection of lower emission-generating resources that are often more costly compared to Idaho Power's current generating fleet. Also, the Company must operate under increasingly complex compliance standards.

Idaho Power's credit quality as measured by the national credit rating agencies has stabilized, albeit at a lesser credit quality than in prior years and at the lower end of investment grade. Rates in effect today–absent one-year impacts of changes to certain tax methods that I will describe later in my testimony–do not provide the Company a sufficient opportunity to earn the rate of return necessary to assure access to the capital markets to finance needed investments under reasonable terms. Any delay in or lack of recovery of prudent operating or financing costs is seen as risk by the financial community, including the credit rating agencies, during this period of plant expansion and difficult economic times. These pressures combine to present a formidable challenge to sustaining the financial health, operational excellence, and, ultimately, the independence of the Company.

Q. You mentioned growth in investment over the past few years. What is driving the growth in investment since the Company's last general rate case?

A. Idaho Power and the utility industry in general are experiencing a cycle of heavy infrastructure investment. Although there has been a pause in the rapid growth experienced a few years ago, growth is still occurring as the Company continues to add new customers. The Company must be prepared to serve that growth as it occurs. To provide safe, reliable service to all customers, the Company must make investments in both new and existing infrastructure. The Company is adding capacity to its base load generation, transmission system, and distribution facilities to ensure an adequate supply of electricity to customers, to provide service to new customers, and to maintain system reliability.

Idaho Power's aging transmission and distribution infrastructure requires continuing investment in upgrades and replacement to maintain their operational viability. The Company's aging hydroelectric and thermal generation facilities also require continuing investment in upgrades and component replacement. In addition, environmental mandates require the replacement or retro-fitting of aging equipment with more expensive technology. Idaho Power has partnership investments in coal facilities that are over 30 years old and require additional investment to maintain their operational viability while continuing to provide low-cost baseload generation. In addition, the Company is operating in an environment of ever-increasing reliability and compliance standards that also require increased levels of investment.

Q. In light of the continued need for investment in new infrastructure for distribution, transmission, and generation resources, what is the Company doing to reduce the need for this new investment?

A. Idaho Power takes its legal obligation to serve the energy needs of its customers seriously. In planning to meet customer energy needs, the Company assesses both supply-side and demand-side options. In addition to expanding its production and delivery systems, the Company is aggressively promoting demand-side management and energy efficiency programs and services. These efforts serve to reduce the pace of growth in investment in a cost-effective manner by delaying the need for additional generating resources. Additionally, these efforts help to educate customers on how they use energy.

Q. Please briefly describe the current business environment in which the Company is operating and expected to operate in up to and through the date rates are adopted in this proceeding.

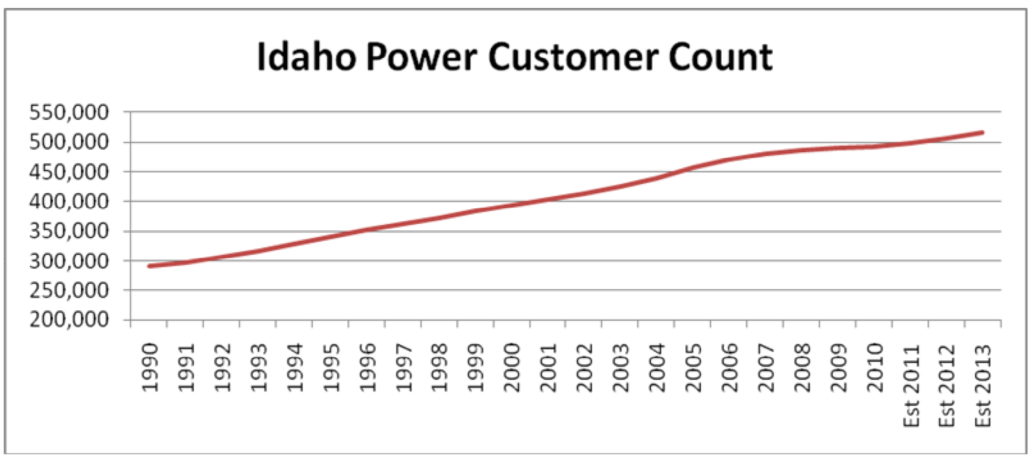
A. The Company's service area continues to experience difficult economic times. However, the current downturn in the economy will not persist forever and Idaho Power must be in a position to respond to its customers' needs as the economy begins to recover.

Q. With the continued negative economic news, why is it that utility investment is expected to increase?

A. Despite all the relatively negative economic news, the forward-looking view is more positive. The May 2011 Oregon Economic Forecast issued by the Oregon Office of Economic Analysis indicated that:

> Similar to the US economy, the Oregon economy appears to be on firmer footing. The job growth picture has improved and Oregon had the 7th fastest job growth year over year for March 2011 among the 50 states. Job growth surged in the first quarter of 2011, which was the third strongest quarterly performance dating back to 1990. The job gains in the first quarter were broad based with virtually all sectors seeing strong growth. The unemployment rate has dropped slightly and was 10 percent in March 2011, compared to 11 percent in March 2010.

As reflected in Appendix A1 of the 2011 Integrated Resource Plan, over the next three years, the Company is expecting billed sales to increase an average of three percent. In addition to this expected growth, other potential new large loads totaling approximately 740 megawatts ("MW") have made inquiries to the Company, of which approximately 20 percent of those inquiries came from the Oregon service area. Overall, the Company expects to add up to 6,000 customers this year. The following graph shows actual and projected growth in number of customers from 1990 through 2013.



This growth, combined with the need to refurbish the existing infrastructure utilized to serve Idaho Power's nearly 500,000 customers safely and reliably on a 24 hours a day, 7 days a week basis, is what continues to drive the Company's new utility investment.

I. INVESTMENT GROWTH

Q. How would you describe the environment that Idaho Power encounters when seeking financing for capital projects?

A. As discussed in Mr. Steven R. Keen's testimony, Idaho Power's credit quality as measured by the national credit rating agencies has become stable only during the last year. However, Mr. Keen believes that Idaho Power will need to show sustained, improved financial results before its credit ratings will improve. Idaho Power is able to raise capital in today's market with its current ratings, but at a higher cost than if its credit ratings were higher. Customers benefit when the Company has ready access to capital markets under reasonable terms in order to finance needed investments in infrastructure.

Q. Please describe the growth of investment since the Company's last rate case.

A. Since the Company's last general rate case in 2009, it has placed in service over $316 million in gross plant.

Q. Please discuss the Company's investment in generation plant.

A. The Company made significant investments in all four of the Jim Bridger Power Plant units to install pollution control equipment as required to comply with the Regional Haze Best Available Retrofit Technology ("RH BART") ruling from the state of Wyoming. Investment in 2011 for the installation of additional pollution control equipment will be required to comply with the RH BART ruling. Also at the Jim Bridger Power Plant, the Company completed a project in 2010 to upgrade the turbines on Unit #1 in order to improve turbine efficiency. In 2011, the Company will also make investments at the Valmy Power Plant Unit #1 to replace the reheating tube, cooling tower and secondary super heater assembly, and to upgrade the evaporation pond liner.

Total nameplate generating system capacity increased by 9 MW from 3,267 MW at the end of 2008 to 3,276 MW at the end of 2010.

Q. Please discuss the Company's investment in its transmission system.

A. In 2010, the Company completed the construction of the new 500 kilovolt ("kV") Hemingway Transmission Station and the associated Hemingway to Bowmont 230 kV transmission line (collectively referred to as "Hemingway") with a total cost of $54 million. Operating constraints in the Northwest and load growth in Idaho Power's service area since 2003 required an additional transmission path coming into the Treasure Valley by the summer of 2010. Hemingway provides that additional route for power to flow into and out of the service area, improves reliability, and is integral to the operation of the system as a whole.

Hemingway proved to be crucial to system reliability in the summer of 2010 when wild fires burned close to the Midpoint 500 kV transmission line. That line had to be taken out of service due to the proximity of the fires. If Hemingway had not been in service, additional sections of the 500 kV transmission system would necessarily have been taken out of service. With Hemingway in service, only the Midpoint to Hemingway section of the line had to be taken out of service, leaving other sections available to serve load.

In 2010, the Company completed a rebuild of the 69 kV Vale to Drewsey transmission line at a cost of approximately $500,000 and the 69 kV Pine Creek to Hells Canyon transmission line at a cost of approximately $360,000. Both of these projects will improve the reliability and performance of the transmission lines.

In 2009, the Company completed the construction of the new 230 kV Danskin to Hubbard transmission line. This project utilized an existing de-energized 138 kV transmission line route and provides enhanced reliability and additional access to the Company's Danskin generation unit.

Total transmission line miles increased from 4,752 miles at the end of 2008 to 4,817 miles at the end of 2010.

Q. Please discuss the Company's investment in distribution facilities.

A. With the installation of 17,500 smart meters and associated station and communication equipment, in 2010, the Company completed the deployment of the Advanced Metering Infrastructure ("AMI") technology in its Oregon service area at a cost of approximately $3 million.

In 2010, Idaho Power installed its first circuit breaker outside the fences of a substation, the HRJA R2 Breaker near Harper, Oregon, at an approximate cost of $300,000. The breaker will function as a reclosure on the 69 kV line to the Drewsey area and will improve reliability in the Vale area. This innovative project saves money because estimated project costs are about one-third of a substation.

Total distribution line miles (overhead and underground) increased from 26,576 miles at the end of 2008 to 26,697 miles at the end of 2010.

II. GROWTH IN EXPENSES

Q. What changes in costs is the Company experiencing which contribute to the need for a rate increase?

A. The Company is experiencing cost increases related to power production, compliance requirements, reliability requirements, materials and supplies, land use fees, maintenance costs, and labor costs. I will briefly discuss some of these changes.

Q. Please discuss increases in power production costs.

A. Power production costs have increased primarily due to operations and maintenance ("O&M") increases passed on to Idaho Power by the Company's operating partners at jointly owned thermal plants. Higher maintenance costs associated with aging equipment, increased labor costs resulting from union contracts that were renegotiated in 2010, and higher chemical costs are the primary drivers of the increases. Costs have increased at the Company's Bennett Mountain plant primarily due to required periodic combustor inspections and combustor parts refurbishment. There have also been price increases in the chemicals used in the thermal plants, along with environmental compliance that requires the use of more chemicals.

Q. Please discuss increases in compliance related costs.

A. There has been an increase in mandatory compliance required of Idaho Power, and utilities in general, related to reliability, environmental compliance, safety, and security. These changes drive corresponding increases in regulatory compliance costs. I will briefly describe some of the areas where compliance related expenses have increased.

The North American Electric Reliability Corporation ("NERC") now requires Light Detection and Ranging surveys to verify transmission line rating values. Costs for 2011 are expected to $1.4 million and the project will be ongoing through 2013.

Beginning in 2011, Idaho Fish and Game hatchery operation expenses are projected to increase $730,000 per year due to a number of factors, including expanded harvest monitoring and harvest performance evaluation, increased personnel, higher Fish and Game O&M and overhead costs, development of a fish identification system, and a contribution toward a region-wide hatchery database.

Cumulatively, Federal Energy Regulatory Commission ("FERC") administrative and land use fees have increased $480,000 since 2008. Western Electricity Coordinating Council ("WECC") annual dues have increased over $200,000, or 33 percent from 2008 to 2011.

In 2011, Idaho Power added three new positions to manage and comply with the increased regulatory compliance requirements of the FERC, NERC, and WECC.

Q. Please discuss increases in reliability requirement related costs.

A. The Energy Policy Act of 2005 significantly impacted the national reliability standards for utilities and changed compliance from voluntary to mandatory starting in June 2007. These standards apply to the bulk power system in North America and are enforced by the NERC and WECC. Non-compliance with any of the requirements may result in monetary penalties up to $1 million per day per violation. NERC's more than 100 reliability standards are mandatory, enforceable, and primarily address system operation, transmission planning, and equipment maintenance.

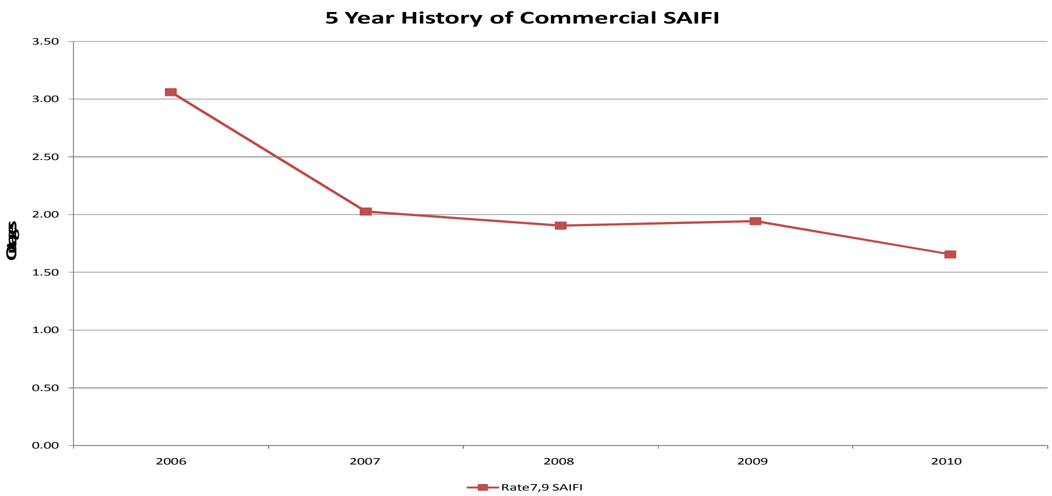
Q. How does Idaho Power measure the reliability of its distribution system?

A. In the electric industry, reliability is, simply put, how good companies are at consistently keeping customers' lights on. Idaho Power measures its distribution system reliability by using industry recognized reliability metrics such as the System Average Interruption Frequency Index ("SAIFI"), the System Average Interruption Duration Index, and the Momentary Average Interruption Frequency Index. In general, these indices look at the average number of outages and the duration of outages experienced by customers across the system.

Q. What are Idaho Power's reliability results?

A. In 2007, the Company increased its focus on reliability and consolidated its reliability activities under one senior manager. Since that time, there have been measured improvements in the Company's reliability metrics. For instance, in 2006, the system SAIFI was 3.06 average outages per year for commercial customers. In 2010, the system SAIFI had improved to 1.66 average outages per year for commercial customers. An outage is defined as an interruption to electric service lasting five minutes or longer. Commercial accounts are one of the customer classes most impacted financially by an outage. Commercial accounts are also fairly evenly spread across the service area. This means that work performed in an area to improve reliability for commercial customers will, in most cases, also improve reliability for a proportional number of customers in other rate classes.

The graph below shows the improvements in the last five years of Idaho Power's commercial customers' SAIFI measurements.



Q. Please briefly describe Idaho Power's recent efforts to improve reliability in its Oregon service area.

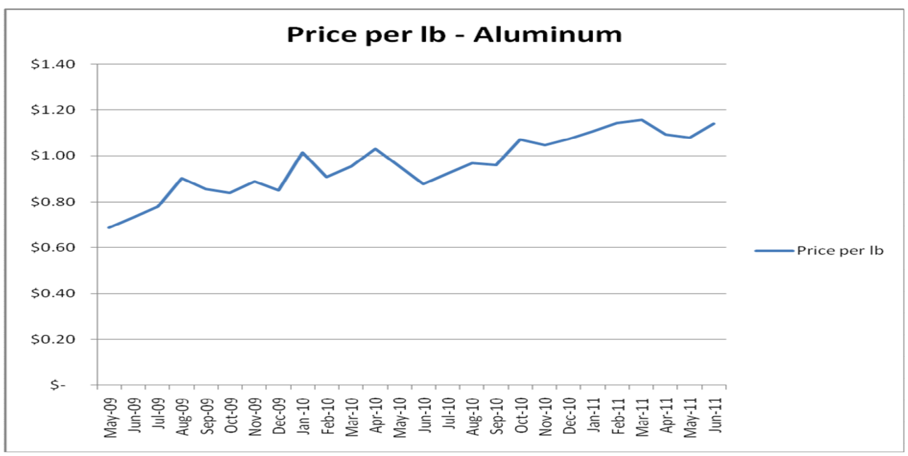
A. In addition to the projects discussed earlier, Idaho Power has completed many projects to either maintain or improve reliability in its Oregon service area. These projects include work such as the maintenance and replacement of certain distribution line equipment devices, replacement of distribution wood cross-arms, rebuilding distribution feeders, replacing distribution wood cross-arms and associated wood pins, injecting and replacing certain underground distribution cables, and improving portions of the transmission system and substations.

Q. Please discuss the increases in material and supply-related costs.

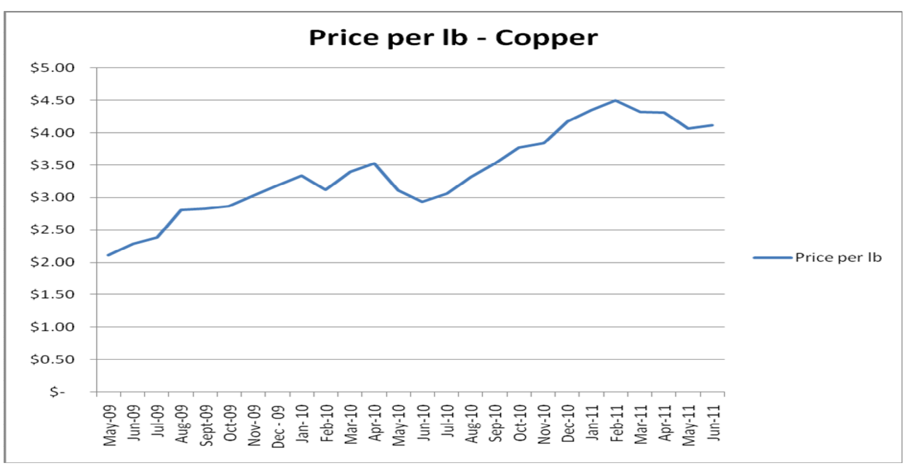
A. Many of the main categories of materials that the Company uses in its operations have seen upward market price shifts in recent years. These categories include transformers, wood poles, pole line hardware, and cable/conductor, which comprise most of the components of the distribution network for serving customers and contribute to overall product costs.

Q. What is causing the increase in the cost of materials for Idaho Power, and the utility industry in general?

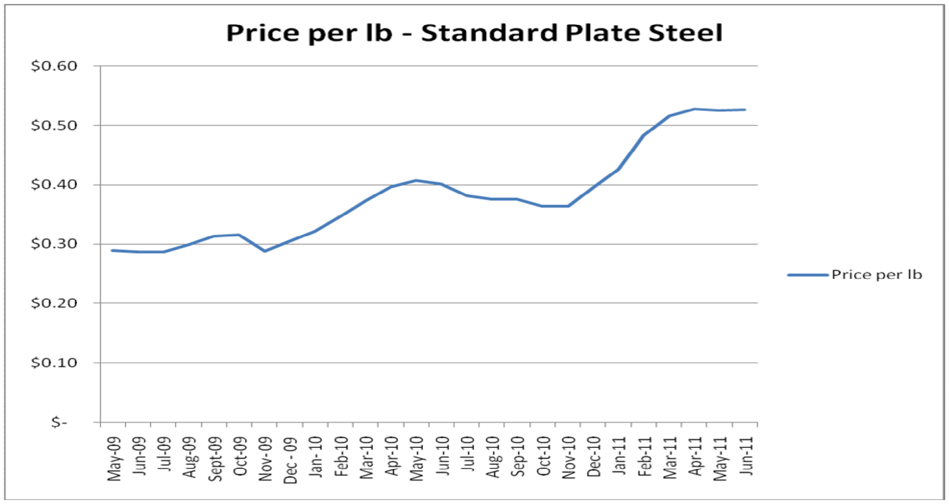
A. A major driver for increases in material costs has been the significant increase in certain commodity costs (copper, aluminum, and steel) over the last few years. These commodities are primary components of many of the materials that Idaho Power utilizes throughout its system. The charts below illustrate the overall upward trend in the prices of key commodities. As can be seen on the chart below, aluminum has increased 66 percent from May 2009 to June 2011.



Copper has likewise increased 95 percent from May 2009 to June 2011.



Standard plate steel has increased 82 percent from May 2009 to June 2011.



Q. What has Idaho Power done to manage the volatility of commodity costs?

A. Idaho Power utilizes a strategic sourcing process to ensure competitive pricing from its suppliers. The process ensures that the Company receives fair market pricing throughout the duration of its agreements with its suppliers by including price adjustment mechanisms (de-escalation/escalation) within its contracts. These price adjustment mechanisms, which are negotiated when the Company has competitive leverage, determine when and how pricing will adjust related to predetermined factors (i.e., commodity prices).

The Company also manages its costs related to transformers. For example, the Company utilizes an in-house refurbishing operation to offset some of the higher costs that the market has presented. The Company refurbishes used transformers that have come from its own operations in addition to buying from the open market. To the extent that refurbished transformers can be used, the unit cost is approximately 30 to 35 percent of the cost of a new transformer.

Q. What is driving the increase in land use fees?

A. Idaho Power pays land use fees to the Bureau of Land Management ("BLM") for its facilities that are located on public lands. At the end of 2008, BLM amended its right-of-way regulations to update the linear right-of-way rent schedule. The new rates took effect in 2009. Land use fees are charged by the acre and based on the land values in individual counties. As an example, in 2011, BLM will charge $159.93 per acre for use of public lands located in Ada County compared to $22.58 per acre in 2008. Overall, BLM land use fees paid by Idaho Power have increased over $1 million on an annual basis from 2008 to 2011.

Q. Please provide a general discussion of Idaho Power's compensation philosophy.

A. Idaho Power's compensation philosophy is to provide a balanced, competitive, and sustainable total compensation package, ensuring it attracts and retains high quality employees and motivates them to achieve performance goals that benefit customers and shareholders. Maintaining a competitive compensation package allows the Company to recruit and retain its highly-skilled workforce. The competitiveness of Idaho Power's compensation package also supports the Company's intent to maintain a flexible workforce that can easily adjust work duties and assignments to meet changing demands and operational needs, which in turn keep the Company's costs of service lower. Thus, because of increases in market compensation, the Company has been required to increase its own labor expense in order to maintain a market competitive compensation package.

Q. Please describe the rationale for the Company's general wage adjustment in 2011.

A. The Company closely monitors trends in the utility industry and attempts to ensure that its overall compensation package is within market ranges. The Company reviews industry specific data from salary budget surveys that are produced by independent consulting firms, including Towers Watson, Mercer, Hewitt, and World at Work. The Company's main objective in this review is to ensure that any general wage adjustment percentage realigns employee compensation at levels that remain competitive when compared to other utilities' annual salary compensation. A further evaluation is conducted that compares the Company's general wage adjusted compensation to compensation provided by a specific group of peer companies comprised of similar-sized, investor-owned utilities and other intermountain utilities. The Company also considers the salary provided by other companies in its service area.

In recent years, the Company has been conservative with its general wage adjustments in comparison with the increases of its peer intermountain utilities. As a result, the Company has fallen behind its peer companies on base salary for some of its critical operations roles, such as skilled craft positions. Again this year, in light of the current economic conditions, Idaho Power decided to grant a general wage adjustment that was below what other peer utilities in the Intermountain West granted.

Q. Please describe the standard the Company uses to remain competitive in setting compensation.

A. The Company has a grade and step pay system. The highest step in any grade is step 13. The Company standard for remaining competitive is to set the step 13 pay to be approximately equal to the median pay for a comparable position in the peer compared market.

Q. What was the general wage adjustment granted in 2011 and how did that compare to other companies in the same industry and/or region?

A. Idaho Power granted a 2 percent general wage adjustment in 2011. According to its analysis of salary increase budget surveys in the utility industry, companies were projecting average structural salary increases of 2.8 percent for 2011. Union contract increases of Idaho Power's peer utilities averaged 2.9 percent for 2011, and the average non-union salary structure increase for the same peer group of companies was 2.8 percent for 2011. The local companies contacted were projecting an average salary structure increase of 2.5 percent for 2011.

The Company's analysis indicates that in recent years, Idaho Power has fallen below its peers such that it will take a 5 percent increase to bring its critical operations positions to the average market base salary rate of its utility peer companies. Given the current economy, the Company has been slow to keep pace with the structural wage adjustments provided by others and is not requesting a rate adjustment that would allow the Company to increase its wages to the same level as its peers.

Q. What else is Idaho Power doing to manage its costs and mitigate the impact of increased costs on its customers?

A. Idaho Power is continually looking for ways to reduce the costs of the services it provides to its customers and for ways to provide those services more efficiently. As seen in the following graph, Idaho Power has done a good job of managing its costs as evidenced by the growth in Idaho Power's O&M expenses compared to the growth in the Consumer Price Index ("CPI") plus the growth in number of customers served expressed as a percentage.

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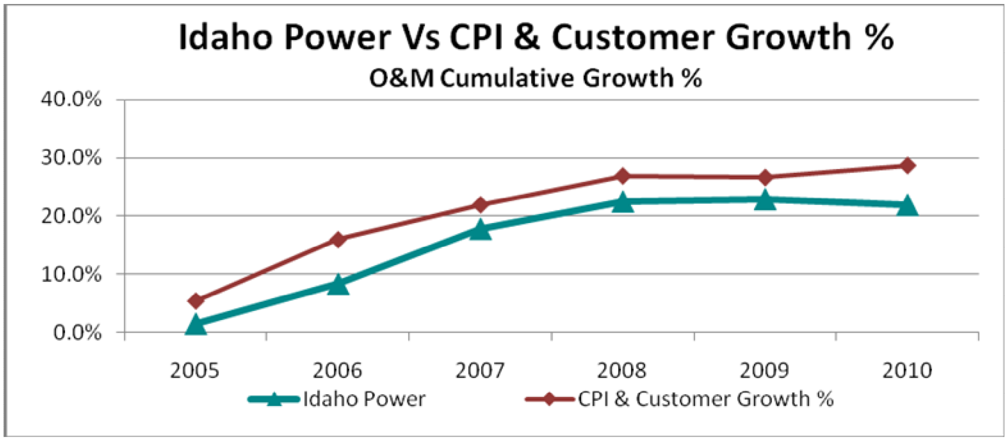
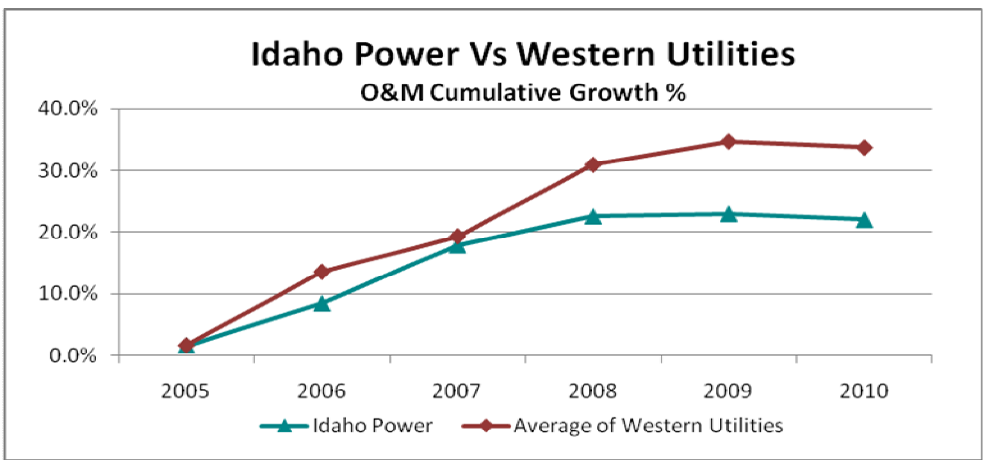


As can been seen in the below graph, Idaho Power has also positively managed its O&M growth as compared to other western utilities.



Q. Can you discuss how the Company has managed expenses?

A. Yes. The Company has been able to reduce employee headcount, control budgets, and reduce required fleet operations.

Q. Please describe the Company's efforts in managing employee headcount.

A. Approval for all replacement or new positions must be reviewed by me or the Executive Vice President of Operations. Employee headcount has decreased by a total of 37 people from the end of 2008 to the end of 2010 and, excluding temporary resources hired for the Smart Grid initiative, headcount has decreased by 70 people during this same time period. This represents a decrease in headcount of approximately three percent from 2008 to 2010, while total customers served increased one percent over the same time period. Therefore, the number of customers served per employee has increased from 234 in 2008 to 241 in 2010. At the end of 2011, total employee headcount is projected to be 42 people lower than at the end of 2008.

Q. Please describe the Company's efforts to control budgets.

A. Idaho Power employs a robust capital and O&M budgeting process. The capital budget process begins with project managers, maintenance personnel, planners, and others within the business identifying needs and submitting projects to business unit management. Business unit management reviews submitted projects and prioritizes them based on spending guidelines provided by senior management. The Company's 2011 annual capital budget is approximately $200 million (excluding the Langley Gulch power plant project), which is down from approximately $249 million actually spent in 2008.

Operations and maintenance budgets are established based on extensive discussions between the business units and senior management, and represent a combination of prior year experience plus or minus identified changes and adjustments. As the Company prepared its O&M budgets for 2011, the target was based on holding to a 2010 budget with only identified unavoidable increases allowed as an adjustment.

Throughout the year, senior management reviews the status of spends for both O&M and capital against short-term estimates as well as original budget. Variances are reviewed and analyzed in order to determine changes that may need to be made during the year to manage to budgeted levels of spend.

Q. Please discuss the reduction in expenses related to fleet services.

A. The Company has significantly reduced the gallons of fuel it uses in its fleet operations by a projected 54,000 gallons from 2008 to 2011. This is mostly due to the reduction of metering vehicles associated with the implementation of AMI and has helped offset some of the significant increases in gasoline prices experienced recently. A recent fleet benchmarking study completed by Utilimarc based on 2009 costs indicated that Idaho Power ranked in the first quartile for cost competitiveness.

III. EARNINGS

Q. What has Idaho Power's system total annual ROE been since 2008?

A. Idaho Power's system total annual ROE was 9.62 percent for 2009 and 10.01 percent for 2010. However, it is important to note that there was a tax benefit related to repairs allowance that occurred in 2010. If not for that tax benefit, the Company's system total ROE would have been 7.9 percent. The testimony of Mr. Keen discusses the tax benefit that occurred in 2010 in greater detail.

Q. Please provide additional discussion of the uniform capitalization method for income taxes ("UNICAP").

A. In 2010, Idaho Power reached an agreement with the Internal Revenue Service related to the Company's uniform capitalization method for tax reporting. This issue is currently awaiting approval from the U.S. Congress's Joint Committee on Taxation ("Joint Committee") and, if approved, Idaho Power would record approximately $60 million of tax benefit in the quarter that the approval is received. Idaho Power cannot predict when the Joint Committee will complete its review or the outcome of that review, but believes the likelihood of receiving a determination in 2011 is enhanced given that the case was submitted in April 2011. Mr. Keen's testimony discusses this issue in greater detail.

Q. Did you provide any specific instructions to the Regulatory Affairs Department in preparing this general rate case filing?

A. Yes. In recognition of the prolonged economic downturn and concern for the impact of any rate increase on Idaho Power's customers, I instructed Mr. Gregory W. Said, Vice President of Regulatory Affairs, to identify areas where the Company could forego requesting an increase at this time. As described further in Mr. Timothy E. Tatum's testimony, Mr. Said directed his department to hold O&M expenses to 2010 levels with the exception of specific cost categories that are "known" to be materially different in 2011 and to hold normalized total power supply expenses to the currently approved normalized levels determined under the October Update component of the 2011 Annual Power Cost Update ("APCU").

Q. Can you summarize the Company's requested rate increase and explain why it is important not only to Idaho Power but in the best interest of customers?

A. This general rate request reflects a revenue requirement increase of approximately $5.8 million, or a 14.67 percent increase and includes a requested ROE of 10.5 percent. As further discussed in Mr. Keen's testimony, this requested ROE is at the bottom end of the recommended ROE range. However, the Company recognizes that in the current economic climate, it is appropriate for the Company to attempt to mitigate the rate impact on our customers, while still providing a fair investment opportunity for the Company's shareholders. This increase is important for Idaho Power to achieve fair and timely recovery of its prudently incurred expenses and a reasonable return on the Company's investment in its electrical system, which today's rates do not fully provide. Continued growth in demand for electricity, aging infrastructure, and higher compliance and reliability requirements are driving the need to invest large amounts of capital to expand and improve electricity supply, delivery, and reliability. This increases the Company's need to access both the debt and equity markets to fund large amounts of capital investment in the system. In this environment, timely and fair recovery of the Company's prudently incurred expenses and investments is critically important to helping it attract capital investment and manage financing costs. A low cost of capital ultimately has a beneficial impact on customers' rates. By providing for fair and timely recovery of the Company's expenses it incurs on behalf of customers and investments in the systems and activities that serve its customers, this rate increase is in the best interests of the Company, its shareholders, and the people and communities it serves.

Q. Does this conclude your testimony?

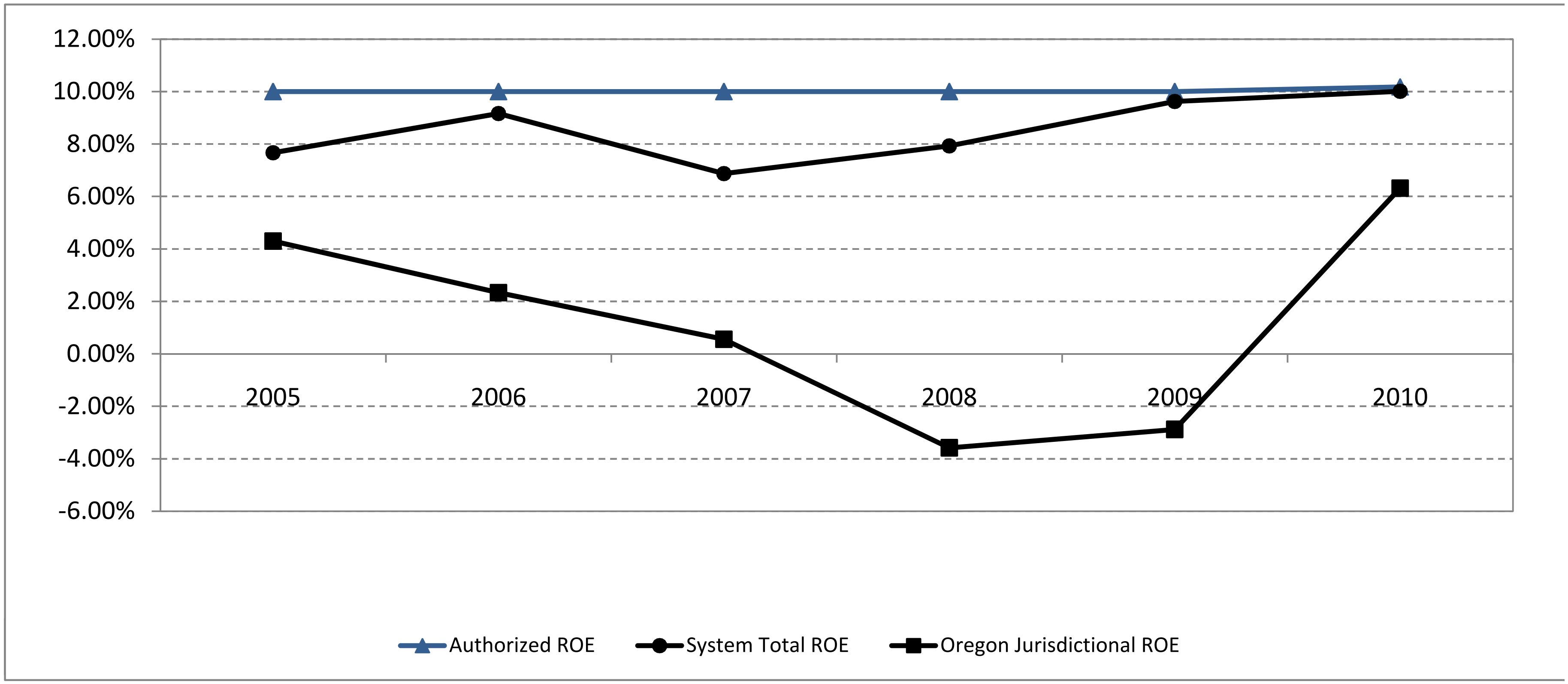
A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Darrel Anderson
Return on Equity Graph

July 29, 2011



Data For Graph

	2005	2006	2007	2008	2009	2010	
Authorized ROE	10.00%	10.00%	10.00%	10.00%	10.00%	10.175%	
System Total ROE	7.66%	9.16%	6.88%	7.92%	9.62%	10.01%	
Oregon Jurisdictional ROE	4.30%	2.33%	0.56%	-3.58%	-2.88%	6.32%	
						1.17%	Average 2005 - 2010

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WARREN KLINE

July 29, 2011

Q. Please state your name and business address.

A. My name is Warren Kline and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. What is your position at Idaho Power Company ("Idaho Power" or "Company")?

A. I am the Vice President of Customer Operations.

Q. Please outline your business experience.

A. I began working full time in the electric utility industry at Idaho Power over 37 years ago, soon after I graduated from high school. For the last six years I have been an officer of the Company. I joined the Company in 1973 in the Customer Service department and have spent the majority of my career with the Company in the customer service and field operations areas. I became a member of the Company's senior leadership team in 1989 when I was named Division Accounting Manager. Since then, I have held positions of increasing responsibility, including Customer Service Manager, General Manager of Customer Service and Metering, General Manager of Regional Operations, and Vice President of Customer Service and Regional Operations. In 2010, I was promoted to my current position as Vice President of Customer Operations.

Q. What educational opportunities have you had while at Idaho Power?

A. While at Idaho Power, I have attended many utility management training programs, including the University of Idaho's *Utility Executive Course*, which I completed in 1989.

Q. What are your duties as Vice President of Customer Operations?

A. I am responsible for the planning, directing, and strategic oversight of all activities within the Customer Operations organization.

Q. Please describe the Customer Operations organization.

A. The Customer Operations organization within Idaho Power is comprised of approximately 600 employees that are engaged in all of the activities that provide direct service to the Company's customers and communities. Specifically, my organization includes Customer Service, Customer Relations and Energy Efficiency, Metering, Regional Operations, Regional Operations Support, Community Relations, and Smart Grid Projects. All of the activities that directly provide service to the customer are in this organization, which allows the employees in the organization to achieve synergies and work together in a seamless manner. The Customer Operations organization exists to provide excellent service to customers in the most cost-effective way possible while still maintaining a strong commitment to safety.

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

A. I will briefly describe some recent changes in the Customer Operations organization and then I will discuss various initiatives that the Company has and is undertaking to provide superior customer service, pursue efficiencies in its operations, and enhance customer choices. Specifically, my testimony will focus on activities in the following areas of the Company that impact customer satisfaction: (1) Customer Operations reorganization; (2) Mobile Workforce Management; (3) Advanced Metering Infrastructure; (4) Smart Grid Projects; (5) Energy Efficiency; (6) Customer Relations; and (7) Customer Service.

I. CUSTOMER OPERATIONS REORGANIZATION

Q. What has Idaho Power done recently to improve customer-focused operations?

A. One of the actions Idaho Power implemented was a reorganization of its regional operations.

Q. Why was this effort undertaken?

A. Responding to the slowdown of the economy, the Company has reassessed its organization and restructured its regional leadership in order to provide for the current needs of its customers and the communities Idaho Power serves.

Technology investments in Advanced Metering Infrastructure and Mobile Workforce Management systems have allowed the Company to adjust its workforce, alter its procedures, and focus on areas of interaction with customers. Idaho Power has made organizational changes designed to leverage the efficiencies associated with new technologies and to enhance customer service. This reorganization has permitted the Company to better align and adjust customer/employee ratios within each region across Idaho Power's service area.

II. MOBILE WORKFORCE MANAGEMENT

Q. What is Mobile Workforce Management ("MWM")?

A. MWM is a software tool that automates and optimizes daily field processes and workflows in real time across Idaho Power's service area, resulting in increased efficiencies and higher customer satisfaction. Field personnel have Mobile Data Terminals ("laptops") in their vehicles that are connected via cellular or satellite technology which in turn relay their location to Mobile Workforce Operators ("Operators") so field personnel can be dispatched most efficiently.

Q. When was MWM implemented?

A. MWM was implemented in November of 2008.

Q. How do customers benefit from MWM?

A. If a customer needs a same day order or has an outage, the Operator can locate the closest employee with the appropriate skill set to complete the order and dispatch him/her to the site. Field personnel who receive the order also receive the exact location on their laptop and can travel directly to the site without further investigation.

The MWM system helps Company employees meet customers' expectations by completing the jobs as promised in a timely manner.

Another benefit of the MWM system is that when field personnel are at a customer's location to disconnect service for non-payment, they have current and complete information that enables them to discuss payment arrangements with the customer, and possibly avoid the disconnection if payment is received or payment arrangements are made onsite. This benefit of MWM eliminates the need for the customer to make a separate call to the Customer Service Center to make payment arrangements at that point in time. In the event that a customer makes a payment or payment arrangements before field personnel arrive, the disconnection can be canceled.

Q. What efficiencies have been gained as a result of this process automation?

A. A number of efficiencies have been realized over time. Before MWM, when new meters were installed, the meter number was written on a piece of paper and then entered into the customer system manually. This process created two points of possible error—both recording and data input. On the other hand, MWM allows the field personnel to scan in the meter number as it is installed, eliminating both sources of possible error.

Throughout the day, orders are completed and the Customer Information System is updated electronically, showing in real time the status of an account. Before MWM, the orders were entered as completed at the end of the day after the field personnel brought them back to the office.

In addition, before the implementation of MWM, orders were printed in the regional offices and manually sorted. Now orders are being sorted automatically by the MWM system and delivered to the laptops during the evening. When the employees arrive at work the following morning, their orders are already sequenced, efficiently routed, and ready to be executed.

By transitioning to a more automated system, employees are more efficient and more accurate, and employee costs are reduced.

III. ADVANCED METERING INFRASTRUCTURE PROJECT

Q. Please briefly describe the Advanced Metering Infrastructure ("AMI") project.

A. In January 2009, the Company began a project to install AMI, including smart meters, for customers across its service area. This technology provides enhanced customer and environmental benefits, reduces operating costs associated with meter reading, and improves meter reading accuracy, outage monitoring, and service restoration.

Q. What type of AMI technology is the Company deploying?

A. After years of extensive technology testing and piloting, Idaho Power determined that power line carrier ("PLC") technology was the best functional and economic fit given the Company's customer density and service area. With this technology, Idaho Power will be able to deploy AMI to approximately 99 percent of all customers and approximately 90 percent of its Oregon customers. (The lower percentage for Oregon customers is due to the fact that the sparse population of Idaho Power's Oregon service area yielded a larger percentage of customers for whom the AMI technology was not cost-effective.) The Company has found the two-way PLC technology to be relatively easy to deploy, robust, reliable, and meets functional needs at a reasonable cost for a large part of Idaho Power's service area.

Q. What is the current status of AMI deployment at Idaho Power?

A. As of the end of June 2011, the Company is 30 months into a 36-month AMI meter deployment plan that began in January of 2009. The Company has installed 390,100 smart meters as part of this phase of AMI deployment. When added to the previous deployment of 28,000 smart meters in Emmett, Idaho, and McCall, Idaho, the total deployment of smart meters is at 418,100 or 85 percent of Idaho Power's total customer base. Deployment of the AMI technology in Idaho Power's Oregon service area was completed in December 2010 with the installation of 17,500 smart meters. Once the new meters are installed, it is typically only a matter of days before customers have the option to view their energy consumption data on the Company's secure website. Idaho Power is on schedule to complete the approximately 79,900 meter installations remaining by the end of 2011.

Q. Please describe your customers' response to the AMI deployment.

A. Overall feedback from customers has been positive. Because the PLC technology can be installed with a simple meter exchange and provide data to the utility and customer in a matter of days, the benefits to customers are almost immediate and the installation can be done without interruption in the normal billing process.

The Company has endeavored to make the deployment of AMI a positive experience for its customers by providing them with information ahead of deployment, answering individual's concerns one-on-one, and by planning and executing the project on schedule without impacting the normal billing process.

Q. Specifically, how does AMI benefit customers?

A. Customers with smart meters have access to their detailed energy usage, thus enabling them to be more informed about their energy consumption and to make wiser choices about their energy usage. With the AMI system, Idaho Power can record energy usage on an hourly basis; in the past Idaho Power could only record total monthly consumption. The recording and management of hourly energy consumption data is the basis for the Company's ability to provide customers with access to detailed data about their individual energy consumption and enables Idaho Power to offer more flexible energy pricing options in the future.

Second, the AMI system supports direct load control by providing commands and confirmation of the action performed by devices installed on customer-owned equipment, such as air conditioners or irrigation pumps. As part of a demand response program, direct load control is used to reduce peak load and help reduce the need for more costly generation resources.

The AMI system will also provide valuable outage scoping and restoration data, enabling Idaho Power to improve outage response and ensure complete restoration of service faster.

Q. What other benefits do customers receive as a result of AMI deployment?

A. As a result of deploying AMI, Idaho Power has virtually eliminated billing estimations and meter read errors, thus also reducing billing errors and bill corrections. Customers can monitor their energy consumption on the Company's website and the pre-bill information enables them to take more control of their energy usage and potentially reduce their bill by managing their energy consumption.

The Company has found that the data from smart meters is helpful in resolving customer billing issues and is a great tool to educate customers on their individual energy consumption patterns and history.

Many customers find the AMI system less intrusive because meter specialists no longer need to access customers' property on a monthly basis to read the meter. Issues with animals, fences, gates, and property access occur much less frequently than with a monthly manual meter reading process.

Q. Are there other benefits?

A. Yes. The environmental benefits from AMI are significant. The Company will remove 75 vehicles from service and eliminate the need to drive more than a million miles a year. This will reduce Idaho Power's carbon footprint, fuel consumption, and roadway congestion.

Moreover, even though Idaho Power has not yet fully integrated the AMI system with the outage management system ("OMS"), the Company has used the system in specific instances to assist in service restoration and confirmation. Once fully integrated with OMS, the system will provide valuable data about outage scope and restoration confirmation that will result in more efficient and timely restoration of power to Idaho Power's customers.

Finally, Idaho Power was able to leverage the AMI project to obtain American Recovery and Reinvestment Act funding through the United States Department of Energy ("DOE") for a Smart Grid Investment Grant ("SGIG") of $47 million at no direct cost to customers.

IV. SMART GRID PROJECTS

Q. Please describe the Smart Grid initiative at Idaho Power.

A. On June 25, 2009, the DOE announced the availability of a SGIG funding opportunity; in response, the Company submitted a proposal for an integrated multi-system project focused on customer service. The application requested DOE funding for $47 million to match the Company's existing $47 million AMI project investment. In October 2009, the Company was notified that its Smart Grid proposal was one of 100 in the country selected to receive a matching grant. Because the Company has already received approval from both the Public Utility Commission of Oregon ("Commission") and the Idaho Public Utilities Commission to pursue the AMI project and exchange existing traditional meters with smart meters, no additional costs will be borne by customers up to $47 million of SGIG spend above AMI costs. This funding opportunity has required significant Company effort to manage, but provides substantial benefits to customers.

Q. Please briefly describe the Smart Grid projects the Company is working on.

A. The Company is pursuing multiple projects that comprise the Smart Grid initiative. The projects are generally characterized and grouped as “customer systems” (which are projects that will provide customer access to smart meter information and programs enabled by the Smart Grid) and “operations systems” (which are electric infrastructure improvement projects that are necessary to fully enable the Smart Grid). My testimony will focus on the customer systems projects described below.

- <u>Customer Information System (“CIS”)</u>. This project upgrades and enhances existing functions of the CIS and adds key capabilities that facilitate more flexible pricing options, a stronger integration with both the AMI system and OMS, and improved operational efficiency.

- <u>Energy Use Advising Tool</u>. This tool will improve the detailed AMI usage analysis capability of Idaho Power’s current Energy Tools and adds new features for both customers and Customer Service Representatives (“CSRs”). Customers will be able to see their “bill to date,” providing useful information on the costs and pattern of energy consumption since their last bill was prepared. CSRs will have enhanced usage and bill analysis information that will allow them to provide more detailed information to customers in order to help them understand their usage and how it affects their bills.

- <u>Meter and Customer Data Warehouse</u>. This project will create a secure analytic database to store meter and customer data that can be used for reporting and analysis, and a more efficient data repository to enhance the efficiency of detailed data viewing for customers and CSRs.

Q. How will customers benefit from the Smart Grid initiative at Idaho Power?

A. The Smart Grid projects will provide measurable results. Customers will have more detailed information about how they use energy so they can be more energy efficient. Advanced technology will also help improve system reliability and reduce outage impacts on customers. In addition to all of the benefits described above, the receipt of the SGIG allows Idaho Power to pursue projects now with little or no investment cost borne by customers rather than at some later date, when all investments would have been borne by customers.

V. ENERGY EFFICIENCY

Q. How does the Company define energy efficiency for purposes of this case?

A. Energy efficiency refers to the Company's activities with respect to energy efficiency, demand response, and its associated outreach and education initiatives.

Q. What is the Company's goal or philosophy towards energy efficiency and demand response?

A. The Company is committed to pursuing all cost-effective energy efficiency and demand response.

Q. How does the Company view energy efficiency and demand response?

A. Cost-effective energy efficiency and demand response programs are the Company's resource of choice–both from a cost standpoint and from an environmental perspective. The cleanest, most efficient resource in the Company's portfolio is the one it does not have to build. The Company believes that cost-effective energy efficiency and demand response should be pursued aggressively.

Q. Please describe the Company's progress in providing energy efficiency and demand response programs.

A. The Company's *Demand-Side Management 2010 Annual Report* was provided to the Commission on April 1, 2011.[1] As noted in the Annual Report, Idaho Power offers 20 energy efficiency and outreach programs and three demand response programs

[1] This voluminous report can be viewed on Idaho Power's website at http://www.idahopower.com/EnergyEfficiency/reports.cfm.

with program options for every major customer class. Energy savings from energy efficiency activities increased on a system-wide basis by 46 percent as compared to 2008. Overall energy efficiency and demand response activities in 2010 resulted in a 358 megawatt (approximately 16 megawatt in Oregon) peak reduction and 187,626 megawatt-hours (approximately 8,631 megawatt-hours in Oregon) in energy savings. Since 2008, the Company has substantially increased the amount of dollars spent on energy efficiency. For example, in 2008, energy efficiency program expenses were about $21 million while, in 2010, the Company spent approximately $46 million. Over 70 percent of 2010 expenses were in the form of program incentives paid to customers. In Oregon, the investment in energy efficiency and demand response increased 167 percent since 2008 and energy savings increased by 154 percent.

Q. Are there any other benefits flowing from the Company's energy efficiency and demand response programs aside from energy saving and demand reduction?

A. Yes. These programs, along with the Company's education outreach and customer energy usage information, provide more opportunities for customers to examine their energy choices. For example, through the Company's outreach programs, customers have opportunities to learn about their energy consumption and how to use energy more efficiently. Using the Company's energy usage presentment tools, customers can see how their hourly energy usage is affected by their energy management decisions and the products they use in their homes and businesses.

Q. What is the source of funding for the Company's energy efficiency activities?

A. The majority of the funding for energy efficiency is from the Idaho and Oregon Energy Efficiency Riders ("Rider") with a lesser amount funded through base rates.

Q. What programs are funded through base rates?

A. Idaho Power funds its low income weatherization program called Weatherization Assistance for Qualified Customers through base rates.

Q. Does the Company participate in or offer energy efficiency related activities other than the programs you mentioned?

A. Yes. The Company sponsors and participates in many organizations and community events that are directly related to energy efficiency efforts. For example, the Company is an active participant in the Northwest Power and Conservation Council's Regional Technical Forum, Northwest Energy Efficiency Alliance, and the Consortium for Energy Efficiency. Company employees participate in many trade shows and community events such as the Malheur County Fair, Treasure Valley Energy Efficiency and Renewable Conference, Western Treasure Valley Electrical Plan Meeting, home and garden shows, agricultural shows, and have presented to many various civic and community groups.

Q. Is there opportunity for public input to the Company's energy efficiency planning process?

A. Yes. Idaho Power relies on the input of the Energy Efficiency Advisory Group ("EEAG") to provide customer and public interest guidance on energy efficiency program design and implementation strategies. Currently, the EEAG consists of 14 members from across Idaho Power's service area and the Pacific Northwest. Members represent a cross-section of customers, including individuals from the residential, industrial, commercial, and irrigation sectors, as well as representatives for senior citizens, individuals with limited income, environmental organizations, state agencies, public utility regulatory commissions, and Idaho Power.

The EEAG meets several times a year and has been instrumental in the development of Idaho Power's programs and studies since 2002. During the meetings, Idaho Power requests recommendations and input on new program proposals, marketing methods, and specific measure details; provides a status update on the Rider funding and expenses; provides updates about ongoing programs and projects; and supplies general information on energy efficiency and demand response issues. Idaho Power relies on and values input from the EEAG to provide a broad customer and public interest review and perspective of energy efficiency and demand response programs and expenses.

Q. Are Idaho Power's energy efficiency programs proving to be successful?

A. Yes. Each program offered has provided benefits to customers and to the Company. Many programs provide monetary incentives to customers for participation, while others target educational efforts and long-term energy saving opportunities. Increased participation in the Company's programs results in wise use of resources and avoids or delays development of supply-side resources.

Q. Do Idaho Power's energy efficiency activities affect customer satisfaction?

A. Yes. Results of the Company's customer satisfaction surveys have shown a steady increase in customer satisfaction over recent years as the percentage of customers who have a positive perception of the Company's conservation efforts increased from 39 percent in early 2003 to 57 percent in late 2010. This represents a 46 percent increase in positive customer perception over the past seven years.

Q. Does Idaho Power support any programs for customers who are having difficulty paying their electricity bills?

A. Yes. Project Share is a year-round energy assistance program which was initiated by Idaho Power in 1982. Project Share, which is administered by the Salvation Army, is funded by a combination of customer donations and Company shareholder funds. In addition, other utilities participate in this program with Idaho Power. Grants from this program can be used for the payment of electricity and gas bills, as well as wood, propane, oil, or coal heat.

During the last program year, more than 6,300 individuals in Idaho Power's communities used Project Share funds to keep their homes warm during cold winter months and cool during hot summer days. In the last five program years ending May 31, 2010, Idaho Power customers have contributed approximately $950,000 and shareholders have contributed approximately $350,000 to the program. In the 2009/2010 program year (ending May 31, 2010), when customer contributions decreased, the Company significantly increased Company shareholder contributions to ensure that funding would not decline during a challenging economic climate.

VI. CUSTOMER RELATIONS

Q. What is the Company's overall approach to customer relations?

A. Idaho Power's vision is to be regarded as an exceptional utility. In order to accomplish this, the Company must provide superior and satisfying customer service that addresses its customers' needs and expectations. Toward this end, the Company continually works to assess customer concerns, identify performance gaps based on customer response, and to explore industry best practices to address those gaps.

Q. What is the Company doing to address areas with opportunity for improvement?

A. The Company's strategy for addressing areas of improvement involves integrating customer input into its processes, systems, and culture while utilizing technology to improve service. For example, as a result of customer input Idaho Power is working on improving system reliability and offering more automated customer service options.

Q. What has Idaho Power done recently to improve system reliability in its Oregon service area?

A. In 2010, per the Stipulation in Docket UM 1470 ("Stipulation"), the Company completed specific upgrades on its Brownlee-Ontario 230 kilovolt transmission line. The upgrades focused on a three-pole structure that had been identified by the

Company as the source of faults that may have impacted the power quality at the H.J. Heinz Ore-Ida Potato Products facility in Ontario. Also per the Stipulation, the Company has installed two fault-locating relays on the Emmett-Ore-Ida Ontario 69 kilovolt transmission line. These relays were installed at the Emmett and Ore-Ida substation terminals on the line.

In 2010, Idaho Power installed its first circuit breaker outside the fences of a substation, the HRJA R2 Breaker near Harper, Oregon. The breaker will function as a reclosure on the 69 kilovolt line to the Drewsey area and will improve reliability in the Vale area. This innovative project saves money because estimated project costs are about one-third of a substation.

Q. What are Idaho Power's system reliability results in Oregon?

A. 2010 results for the reliability indices of System Average Interruption Duration Index, System Average Interruption Frequency Index, and Momentary Average Interruption Frequency Index remained below threshold as reflected in the *2010 Electric Service Reliability Annual Report* filed with the Commission and attached as Exhibit 301.

Q. Please describe Idaho Power's continuing practice of surveying customer satisfaction.

A. Idaho Power has contracted with Burke, Inc. ("Burke") to conduct quarterly customer relationship surveys since 1995. Burke is a full-service customer market research and decision support company headquartered in Cincinnati, Ohio, with regional offices throughout the United States. The Burke surveys represent Idaho Power's primary customer satisfaction research. In addition to the Burke surveys, Idaho Power acquires the results of the annual J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study ("J.D. Power Study"). The J.D. Power Study is used primarily as a benchmark to other electric utilities. As its name implies, the J.D. Power Study is for residential customers only, as the number of Idaho Power commercial customers is not large enough at this point in time to qualify for a subscription to the J.D. Power Study. Idaho Power ranked in the top quartile of the 124 utilities in the 2011 J.D. Power Study. Moreover, in that same study, Idaho Power ranked highest of *all* utilities included in the study for the fourth year in a row for providing customers the information they want, and need, regarding outages. Idaho Power also utilizes customer focus groups for project-specific qualitative research when the situation is appropriate.

Q. Please describe the Company's customer satisfaction performance results in recent years.

A. I am proud to say that based on the Burke surveys, Idaho Power customers' satisfaction remains at a consistently high level. In addition, the Company is experiencing levels of customer satisfaction that are significantly higher than when it began measuring in 1995. Results of the 2011 J.D. Power Study also reflected very consistent and improved performance by Idaho Power with regard to residential customer satisfaction in all components of the J.D. Power customer satisfaction index, including power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service.

Q. Please summarize the Burke methodology and the resulting information made available to the Company.

A. On a quarterly basis, Idaho Power receives results from Burke based on customer interviews. Quarterly results include an overall index score, referred to as the Customer Relationship Index ("CRI"), as well as more detailed information in the form of average response data collected for numerous questions in six general categories: (1) Company Image; (2) Quality of Service; (3) Cost and Pricing; (4) Responsiveness to Customers; (5) Communication; and (6) Billing and Payment.

Q. What is Idaho Power's primary way of measuring its success in providing customer satisfaction?

A. Idaho Power's primary measure for customer satisfaction is the CRI derived by Burke from quarterly customer surveys. The CRI is based on research that is conducted at various points in time throughout the year. This reduces the potential for any one event or circumstance to have a significant influence, either good or bad, on the overall customer satisfaction levels. It is a statistically reliable measurement of customer opinions and it provides a historical trend that allows the Company to track its performance over time. The CRI is the best single satisfaction measure available to Idaho Power because it depicts the customers' overall attitudes toward the Company in five distinct criteria. The CRI is comprised of five key questions where a rating ranging from zero (very dissatisfied) to four (very satisfied) is given for a maximum of 20 points possible among all five questions. The following are the five criteria questions that are asked in the quarterly customer surveys:

> (1) What is your overall level of satisfaction with Idaho Power?
>
> (2) How much do you agree or disagree that the overall quality of the electricity and customer service and support you get from Idaho Power is excellent?
>
> (3) Thinking about the price you pay, how much do you agree or disagree that the overall value of the electricity and customer service and support you get from Idaho Power is excellent?
>
> (4) If asked (by a neighbor new to your area, by a company that just moved into the area, by an irrigator new to your area,) how likely would you be to tell them that Idaho Power is a good company to work with?
>
> (5) How much do you agree or disagree that Idaho Power cares about you as a customer and has done everything possible to earn your loyalty?

Responses for each customer are totaled and divided by the maximum possible points to establish a percentage CRI score. The CRI can range from a minimum of zero to a maximum of 100 percent.

Q. Would you please describe the Company's customer satisfaction performance?

A. Idaho Power achieved a CRI of 82.30 for the 12 months ending the fourth quarter of 2010. According to Burke, a score of 82.30 signifies that overall customers have very strong positive attitudes towards Idaho Power and the level and quality of service it provides. Overall, the level of customer satisfaction has remained fairly consistent since the 12 months ending the fourth quarter of 2008.

VII. CUSTOMER SERVICE

Q. Would you please briefly describe Idaho Power's Customer Service organization?

A. Idaho Power operates a centralized Customer Service Center that provides customers with full service access to CSRs weekdays from 7:30 a.m. to 6:30 p.m. and outage and emergency access to Outage Specialists twenty-four hours a day, seven days a week. Idaho Power employs bilingual CSRs that provide service to the Company's Spanish-speaking customers. Additionally, the Company utilizes a third-party language service to help it communicate with other non-English speaking customers. On average, approximately 1.2 million inbound customer calls are received by the Customer Service Center each year.

In addition to the services provided by CSRs during business hours and by Outage Specialists 24 hours a day, 7 days a week, Idaho Power also provides its customers access to account and outage information 24 hours a day, 7 days a week through an Interactive Voice Response ("IVR") unit. Through the IVR, customers can make payment arrangements; retrieve billing, payment, and meter reading information; sign up for Budget Pay; access energy efficiency and usage information; and receive information on outages. Account access is available 24 hours a day via the Company's secure website. This allows customers the same "self-help" options available through the IVR, plus the ability to start and stop service and engage in an energy usage analysis for their home or small business.

Q. You mentioned Idaho Power was undertaking several customer-oriented initiatives. Do any of these initiatives directly impact the way Idaho Power delivers customer service?

A. Yes. The Company is implementing a new Customer Service Call Management System. This system provides several new features to customers including a "virtual hold" option through the IVR and a "call me" option through Idaho Power's website. In addition, it allows for more sophisticated proactive dialing campaigns, improved efficiency in employee scheduling, greater data analysis capability, and improved quality assurance monitoring.

Q. Are there any other customer service initiatives being undertaken?

A. Yes. The Company has heard from its customers that they would like a no-fee, on-line bank debiting payment option. In response to this feedback, the Company is developing a no-fee bill payment option to be available to customers who utilize its Account Manager functionality on its website. This option, which is scheduled to be available in August 2011, will allow customers to schedule no-fee electronic payments from their checking or savings account. This payment option will provide more flexibility and convenience to customers and is expected to reduce overall payment processing costs as customers who currently use pay stations for same-day payments will have the ability to make those payments without leaving their homes or businesses.

Q. You mentioned earlier that Idaho Power is committed to providing superior service to its customers. Do you believe the initiatives undertaken within your Customer Operations organization meet this commitment?

A. Yes. Idaho Power is committed to providing superior service to its customers in all facets of its business. I believe the organizational changes made over the past few years as well as the initiatives completed and currently underway demonstrate Idaho Power's commitment to its customers to provide superior and satisfying service.

Q. In your opinion, should the Company's requested rate increase be viewed as reasonable based upon the Company's customer service and customer satisfaction performance?

A. Yes. By providing the Company with fair and timely recovery of its revenue requirement, the Commission will be recognizing that the Company has adequately addressed customer needs and that the Company's investments that support customer service and satisfaction have been appropriately incurred on behalf of customers.

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

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Warren Kline
Idaho Power Company 2010 Electric Service Reliability Annual Report

July 29, 2011

Idaho Power Company
2010 Electric Service Reliability
Annual Report

This document is written to present Idaho Power Company's 2010 Electric Service Reliability Annual Report. The report discusses the performance of Idaho Power Company's Oregon electric service through a narrative summary as well as attached tables and charts.

At the end of 2010, Idaho Power served 19,409 customers from 62 distribution circuits in the far central-eastern portion of Oregon.

The composite performance of the 62 circuits in 2010 included 863 sustained (>5 minutes) interruptions, 636 momentary events, 91,430.82 customer hours out, a SAIDI of 4.98, a SAIFI of 1.62 and a MAIFI_E of 3.78.

SAIFI remained below threshold for interruptions by.2.1% in 2010. SAIDI was below threshold for customer hours out by 0.81% and MAIFI_E momentary interruptions were below threshold by 2.61%. We continue to gather more momentary data through the Sentry units but with the drawback of only an Unknown cause.

Attached System CHARTS & TABLES show Oregon system performance (all of IPC's 62 Oregon circuits) over 5 years for the reliability indices of SAIDI, SAIFI and MAIFI_E**.** TABLE 1, TABLE 2 and TABLE 3 lists 5 years of circuit reliability and threshold data for the three reliability indices. TABLE 4 lists 2010 circuit data for the 3 reliability indices in descending order. CHARTS 1-3 provide graphic representation of the circuits in descending order for the 3 reliability indices. Also attached, are charts for each Oregon circuit by reliability index..

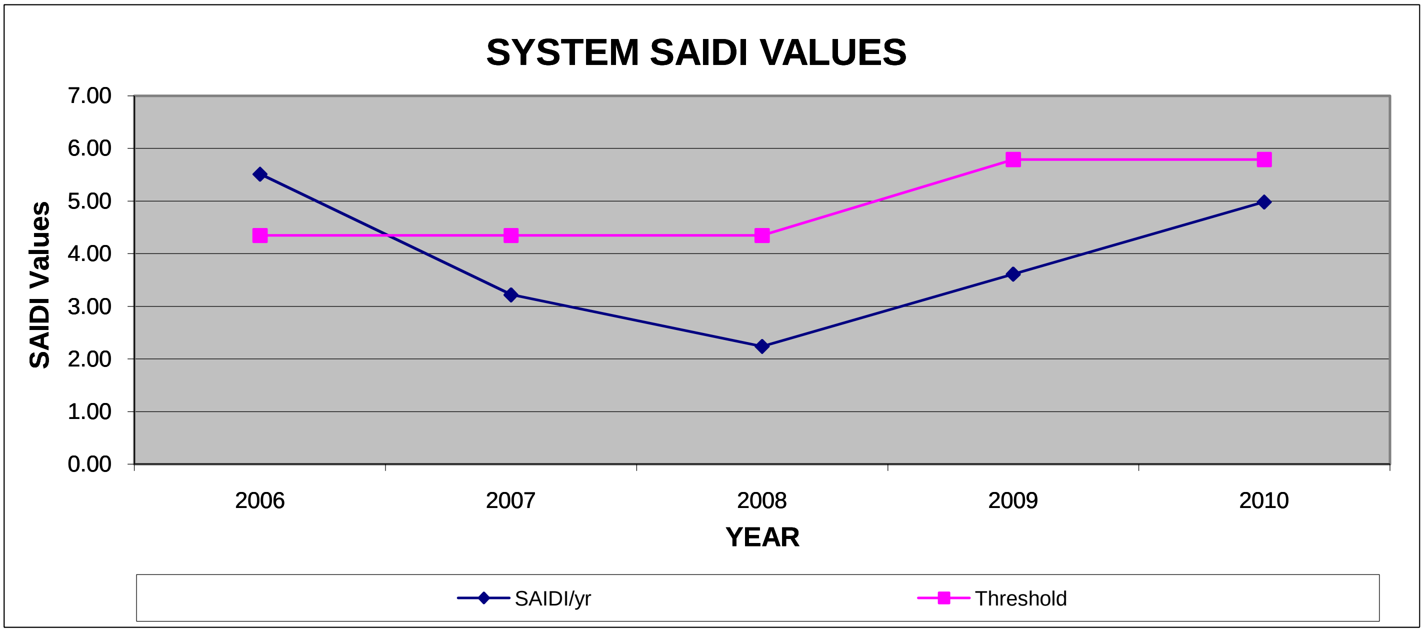
The top 5 causes of Idaho Power Company's sustained interruptions in 2010 were due to Unknown, Equipment Failure, Scheduled Outages, Adverse Environment and Foreign Interference. Please refer to TABLE 5 for a breakdown by cause and the associated number of occurrences for each cause as well as the percentage of the total for the last five years. TABLE 6 provides a ranking of the 2010 sustained interruption causes by occurrences and by customer hours without electricity service. The attached CHARTS for Interruption causes shows 5 years of system data for each of the 12 types of interruption causes. CHART 4 is a pie chart that shows the 12 types of sustained interruption causes as a percent of total.

TABLE 7 lists the circuits that exceeded the threshold level for any of the 3 reliability indices. Seven circuits exceeded their SAIDI threshold level, 3 circuits exceeded the SAIFI threshold level and 12 circuits exceeded the MAIFIe threshold level.

TABLE 8 provides 5 years of line/trench miles and customer count data. Data differentiating overhead from underground service is now available and is included in this table.

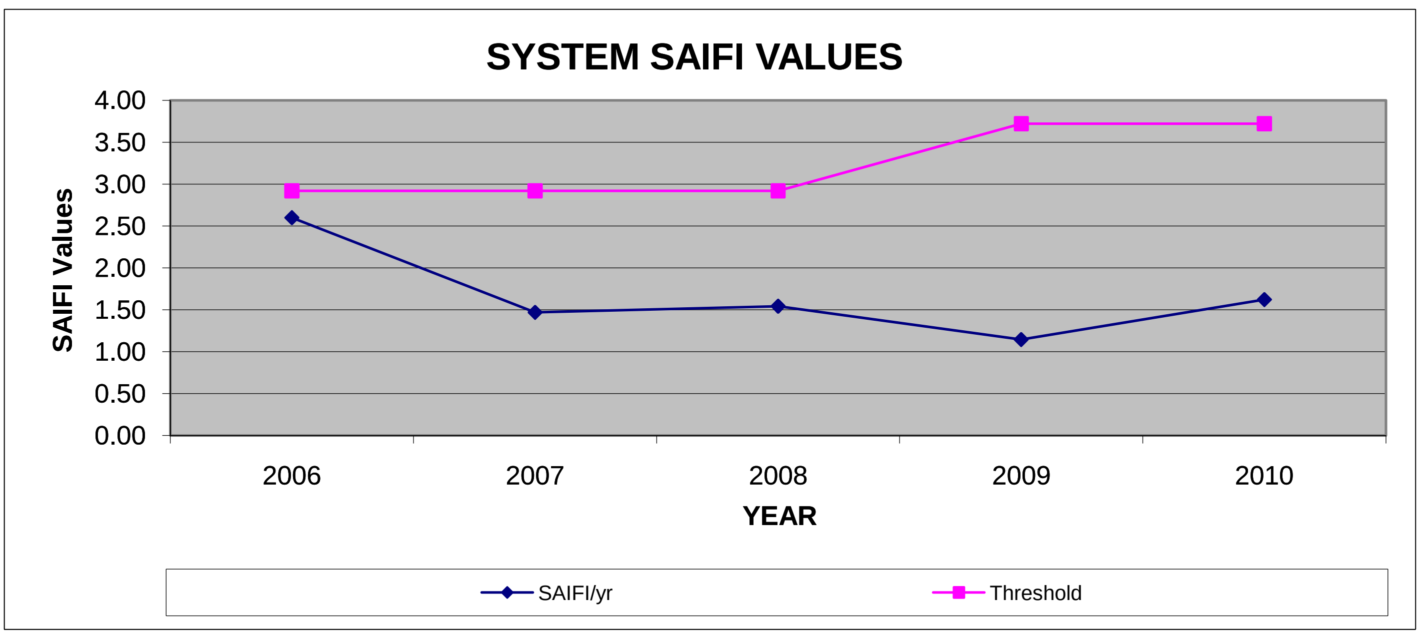
Idaho Power Company continues with periodic programs and projects to help improve customer service and electric service reliability. Some of the programs include our annual Oregon safety inspection/reliability patrols, line clearing program and annual maintenance projects.

5 Years of System Reliability Data and Associated Thresholds



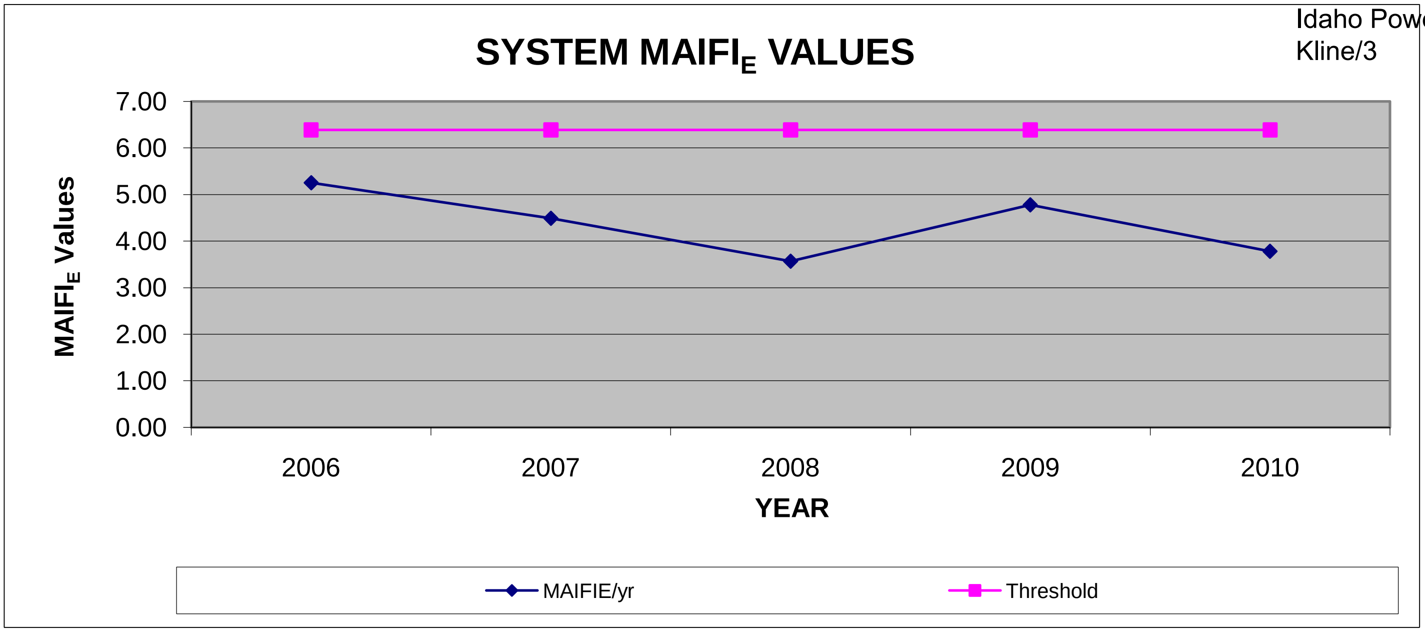
SYSTEM SAIDI VALUES

2006	2007	2008	2009	2010	THRESHOLD
5.51	3.22	2.24	3.61	4.98	5.79



SYSTEM SAIFI VALUES

2006	2007	2008	2009	2010	THRESHOLD
2.60	1.47	1.54	1.14	1.62	3.72



SYSTEM MAIFI$_E$ VALUES

2006	2007	2008	2009	2010	THRESHOLD
5.25	4.49	3.57	4.78	3.78	6.39

5 Years of Circuit SAIDI Data and Associated Thresholds

TABLE 1

SAIDI Values

CIRCUIT	2006	2007	2008	2009	2010	THRESHOLD
CARO11	2.51	1.43	1.26	0.73	5.48	14.91
CARO12	6.28	0.90	4.02	0.13	0.94	6.86
CARO13	0.85	0.43	0.31	0.08	1.75	1.45
CWVY11	8.86	2.97	3.14	0.33	2.98	7.88
CWVY12	10.26	8.13	10.44	2.61	50.35	14.19
DRKE11	3.31	10.50	3.55	9.42	11.67	13.70
DUKE11	14.62	0.54	5.93	2.96	0.00	14.12
DWSY11	8.20	54.99	7.28	5.19	2.37	29.00
ESTN11	0.61	24.68	7.97	1.57	9.72	34.60
HCSU11	0.00	0.00	0.00	0.00	0.00	5.37
HFWY11	18.15	2.16	4.10	4.16	21.65	11.83
HFWY12	23.94	6.99	12.96	7.10	0.18	26.73
HGTN11	2.34	0.65	1.29	2.30	15.86	31.26
HGTN12	1.42	0.00	0.00	0.03	3.86	5.16
HMDL12	5.11	3.26	5.01	10.87	2.48	34.47
HOLY11	3.97	0.26	4.70	3.65	4.48	9.73
HOLY12	0.22	0.63	0.25	1.63	2.62	4.86
HOLY13	5.12	2.87	0.81	2.01	2.24	9.34
HOPE11	9.14	8.82	6.01	3.09	5.67	12.96
HRPR11	19.56	14.51	5.94	15.35	26.48	28.69
HRPR12	11.43	14.07	18.58	13.83	11.13	32.42
JMSN11	7.31	9.07	0.71	4.59	8.24	10.12
JMSN12	9.70	6.53	0.61	1.01	4.90	7.58
JNTA11	0.26	44.57	7.40	5.91	7.81	25.19
JNTA12	0.25	46.01	6.13	1.76	9.38	19.88
JNVY11	14.79	4.56	3.63	19.28	36.95	64.44
JNVY12	13.47	2.90	8.71	20.93	44.29	28.11
JNVY31	26.57	6.16	10.58	31.32	38.77	128.22
LIME11	8.42	9.85	0.71	7.05	15.90	51.54
LIME12	1.71	5.03	0.51	0.03	25.53	12.07
MRBT41	0.61	2.20	7.05	1.86	1.09	11.26
MRBT42	1.70	0.22	0.37	0.28	0.15	25.14
NYSA11	2.76	0.04	0.33	2.71	0.46	4.20
NYSA12	14.11	0.40	2.28	1.16	1.49	37.43
NYSA13	4.16	1.18	4.13	1.85	0.22	16.43
NYSA14	5.57	3.19	0.13	0.70	0.05	8.58
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OBPR12	0.00	0.00	0.00	0.00	0.00	1.00
OIDA11	0.33	4.32	1.79	0.06	0.41	17.65
OIDA12	0.82	2.14	0.00	1.55	4.90	4.57
ONTO14	0.08	7.50	0.70	0.50	1.23	17.26
ONTO18	1.62	0.41	0.16	0.03	0.21	2.96
ONTO19	1.00	0.88	0.22	0.11	1.67	1.54
ONTO20	2.02	0.83	0.17	1.46	0.33	3.75
ONTO23	5.76	11.26	0.00	0.83	0.58	50.45
ONTO24	0.60	5.07	1.59	1.03	2.18	6.73
ONTO25	0.25	0.30	0.02	0.12	0.14	0.66
OYDM11	6.64	0.00	0.20	0.00	0.67	14.36
PNCK11	23.93	0.07	8.87	1.29	17.36	18.07
PNCK12	53.54	0.00	1.28	0.00	0.00	23.00
PRMA12					0.83	0.00
PRMA42	6.44	0.94	6.22	6.24	6.64	25.36
RKVL11	39.84	3.83	43.75	21.75	54.96	78.56
UNTY11	22.34	3.68	2.73	0.65	0.47	15.03
UNTY12	17.86	5.39	2.51	0.87	0.31	10.67
VALE11	0.59	0.67	0.37	0.29	0.75	4.37
VALE13	3.81	2.98	0.43	34.59	19.98	39.28
VALE14	4.12	6.95	0.48	0.92	2.67	20.45
VALE15	1.09	0.35	5.48	0.53	0.54	7.35
WESR13	5.68	0.85	0.22	7.79	1.52	33.48
WESR14	24.44	1.10	0.17	0.91	0.52	56.58
ADRN11				2.31	0.15	28.37
ADRN12				3.45	0.50	95.64

5 Years of Circuit SAIFI Data and Associated Thresholds

TABLE 2

SAIFI VALUES

CIRCUIT	2006	2007	2008	2009	2010	THRESHOLD
ADRN11				2.20	0.10	13.00
ADRN12				1.73	0.11	8.00
CARO11	0.77	1.52	2.67	0.47	4.47	9.50
CARO12	1.36	1.77	2.41	0.24	1.07	7.24
CARO13	0.99	0.15	2.06	0.05	1.07	3.14
CWVY11	3.17	1.02	2.02	0.13	0.27	3.21
CWVY12	3.21	2.43	2.66	0.73	3.17	3.65
DRKE11	1.28	3.91	1.04	5.30	4.35	6.49
DUKE11	6.74	0.96	1.70	2.31	0.00	7.09
DWSY11	3.14	8.58	4.95	3.25	1.29	8.77
ESTN11	0.33	3.00	3.00	1.00	7.00	6.00
HCSU11	0.00	0.00	0.00	0.00	0.00	3.00
HFWY11	8.52	1.09	2.08	1.50	5.14	7.30
HFWY12	9.80	3.07	6.07	2.46	0.11	11.48
HGTN11	1.38	0.27	0.29	1.02	3.29	5.78
HGTN12	1.07	0.00	0.00	0.01	1.14	2.05
HMDL12	3.40	2.46	3.61	7.60	2.34	22.56
HOLY11	2.38	0.19	3.28	3.33	3.14	6.79
HOLY12	0.06	0.33	0.20	1.17	3.27	4.34
HOLY13	0.58	0.47	0.65	1.31	2.42	3.58
HOPE11	3.82	5.55	4.46	3.20	2.24	7.44
HRPR11	6.12	6.17	4.12	3.21	8.06	9.12
HRPR12	3.47	5.87	5.07	3.52	4.37	8.07
JMSN11	2.46	2.25	1.26	2.26	3.77	4.40
JMSN12	5.53	2.10	1.19	0.52	1.48	5.36
JNTA11	0.08	5.88	4.25	2.27	3.42	6.56
JNTA12	0.06	7.45	2.88	1.12	4.30	6.02
JNVY11	4.55	1.24	1.16	6.26	8.19	19.99
JNVY12	3.94	1.16	3.24	6.12	7.56	8.88
JNVY31	6.26	1.92	1.67	8.59	8.26	30.10
LIME11	3.07	3.02	0.31	2.52	1.94	16.61
LIME12	0.78	1.79	0.29	0.04	5.04	4.80
MRBT41	0.45	2.32	0.59	0.39	1.22	2.89
MRBT42	1.11	0.89	0.20	0.20	0.10	3.32
NYSA11	3.52	0.02	1.10	1.86	0.77	4.52
NYSA12	7.08	1.10	2.58	1.20	0.95	23.14
NYSA13	4.62	1.56	3.94	1.95	0.16	15.90
NYSA14	2.60	2.65	0.99	1.17	0.03	5.62
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OBPR12	0.00	0.00	0.00	0.00	0.00	1.00
OIDA11	0.14	2.37	0.80	0.03	0.66	9.67
OIDA12	1.00	2.00	0.00	1.00	4.00	4.00
ONTO14	0.19	2.38	0.98	1.00	1.00	7.55
ONTO18	1.62	0.90	0.18	0.04	0.10	3.32
ONTO19	0.25	0.82	0.16	0.05	0.53	1.00
ONTO20	0.28	1.00	0.07	0.12	0.21	1.40
ONTO23	1.95	3.70	0.00	1.98	1.02	17.38
ONTO24	0.33	3.22	1.31	0.50	1.90	4.51
ONTO25	0.87	0.24	0.01	0.04	0.09	1.33
OYDM11	1.68	0.00	0.23	0.00	0.27	5.70
PNCK11	7.51	0.05	4.32	0.61	3.95	7.77
PNCK12	7.00	0.00	1.00	0.00	0.00	5.50
PRMA12					0.50	0.00
PRMA42	8.19	1.15	4.37	3.94	3.16	17.64
RKVL11	4.67	1.38	6.79	5.96	6.28	10.84
UNTY11	7.95	1.14	2.13	0.19	0.16	5.97
UNTY12	5.61	1.89	2.03	0.22	0.82	4.28
VALE11	0.38	0.35	1.12	0.24	0.31	3.87
VALE13	1.61	1.61	1.23	0.49	3.58	3.57
VALE14	1.23	1.10	1.23	0.49	1.55	5.38
VALE15	0.63	1.03	3.10	0.24	0.23	4.26
WESR13	2.16	0.63	0.15	2.25	0.47	6.72
WESR14	7.47	2.05	0.08	0.22	0.35	12.62

5 Years of Circuit MAIFIE Data and Associated Thresholds

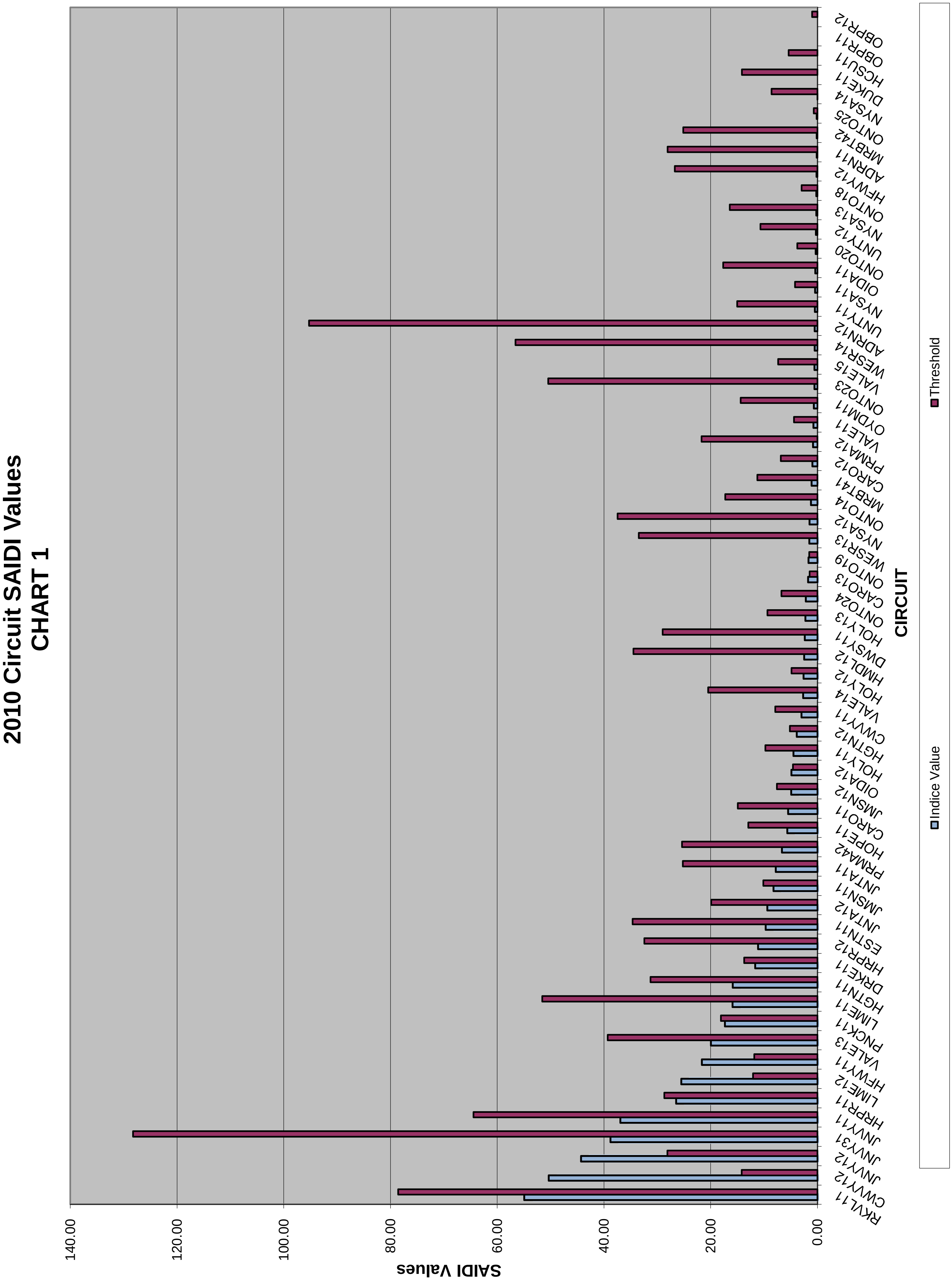
TABLE 3

	MAIFIE Values					
CIRCUIT	2006	2007	2008	2009	2010	THRESHOLD
ADRN11				2.91	1.73	5.87
ADRN12				5.36	2.61	5.87
CARO11	9.13	3.09	3.91	3.04	2.81	15.33
CARO12	10.47	2.34	3.33	2.00	4.27	9.46
CARO13	4.00	1.11	3.00	4.00	3.00	6.99
CWVY11	11.00	8.96	10.00	10.00	7.00	13.00
CWVY12	20.90	15.26	10.55	9.98	11.62	13.45
DRKE11	15.01	6.00	2.00	19.13	6.04	8.00
DUKE11	3.00	10.04	6.00	6.00	2.00	12.91
DWSY11	44.71	10.06	16.76	5.87	19.53	20.84
ESTN11	2.00	2.00	0.00	0.00	0.00	12.13
HCSU11	0.00	0.00	0.00	0.00	0.00	4.00
HFWY11	22.78	11.18	5.27	9.50	15.60	14.95
HFWY12	13.32	13.11	9.03	8.79	9.20	14.81
HGTN11	13.90	3.06	2.11	4.10	1.20	6.78
HGTN12	7.00	2.00	1.00	2.00	0.00	4.00
HMDL12	3.32	7.00	11.80	40.98	20.03	5.00
HOLY11	5.00	2.03	4.00	3.00	1.00	6.00
HOLY12	5.00	0.00	5.00	2.00	1.00	5.00
HOLY13	5.12	3.14	6.16	5.28	1.49	4.80
HOPE11	32.26	10.33	17.00	6.00	22.17	24.29
HRPR11	32.56	10.89	14.30	7.00	17.00	21.50
HRPR12	65.79	14.81	21.64	7.65	23.07	22.95
JMSN11	18.00	11.00	9.00	14.00	13.00	13.00
JMSN12	18.50	9.57	8.38	9.93	6.00	13.62
JNTA11	28.33	7.14	18.00	4.00	19.00	19.95
JNTA12	40.92	6.56	16.00	4.00	20.00	18.97
JNVY11	12.26	6.43	9.22	12.45	6.36	12.00
JNVY12	10.00	6.00	10.00	22.00	14.00	9.00
JNVY31	55.03	9.77	11.81	24.03	19.54	10.00
LIME11	20.23	7.00	1.00	8.00	4.77	4.00
LIME12	13.65	4.66	1.27	2.00	2.35	3.00
MRBT41	4.00	4.00	4.00	11.00	5.00	9.69
MRBT42	8.00	3.00	7.00	3.00	0.00	6.00
NYSA11	0.79	1.00	1.00	0.00	0.60	5.00
NYSA12	8.12	2.19	5.78	4.62	1.08	9.70
NYSA13	2.25	3.29	1.86	0.07	0.00	5.87
NYSA14	2.90	1.75	1.00	0.39	1.00	3.00
OBPR11	0.00	0.00	0.00	3.59	3.59	2.00
OBPR12	0.00	0.00	0.00	0.00	0.00	2.00
OIDA11	2.00	5.17	5.19	0.00	1.30	5.00
OIDA12	1.00	1.00	0.00	0.00	1.00	7.00
ONTO14	1.00	1.00	0.00	2.00	1.00	13.00
ONTO18	0.00	1.00	1.00	4.00	1.00	5.00
ONTO19	2.27	3.02	1.00	2.00	6.00	7.99
ONTO20	2.00	2.00	0.00	5.17	1.00	9.03
ONTO23	4.00	5.00	3.63	0.00	1.00	9.00
ONTO24	6.21	7.19	3.00	2.00	14.00	7.81
ONTO25	3.00	1.99	3.63	17.45	1.00	5.00
OYDM11	8.00	2.00	9.45	0.00	0.00	1.88
PNCK11	19.91	8.84	0.00	8.70	6.23	19.66
PNCK12	0.00	4.00	34.96	20.00	0.00	14.00
PRMA12					0.00	0.00
PRMA42	8.66	4.65	4.00	14.07	9.00	10.00
RKVL11	11.00	6.00	14.13	10.07	11.00	3.00
UNTY11	15.06	9.25	12.90	3.27	14.00	13.00
UNTY12	29.36	8.95	3.00	6.61	7.56	13.38
VALE11	2.65	1.77	3.71	2.07	1.54	3.99
VALE13	11.10	7.36	4.00	2.70	10.37	5.82
VALE14	0.06	6.06	1.47	0.52	2.00	7.31
VALE15	9.29	1.00	3.00	1.00	0.67	5.23
WESR13	3.83	3.83	11.00	0.52	3.79	3.83
WESR14	10.00	10.00	3.79	1.00	1.00	10.00

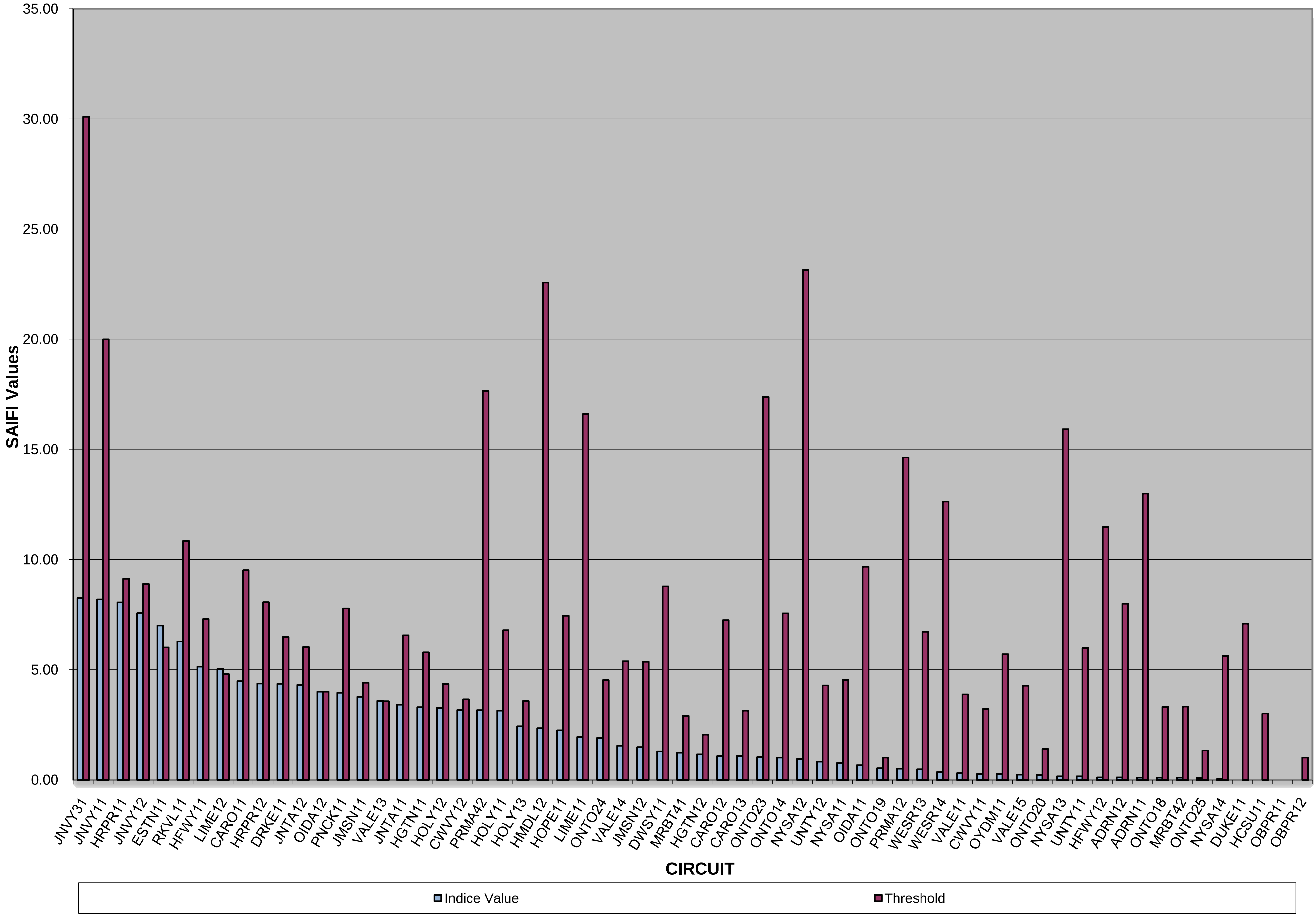
2010 Descending Order Sort of Reliability Indices by Circuit

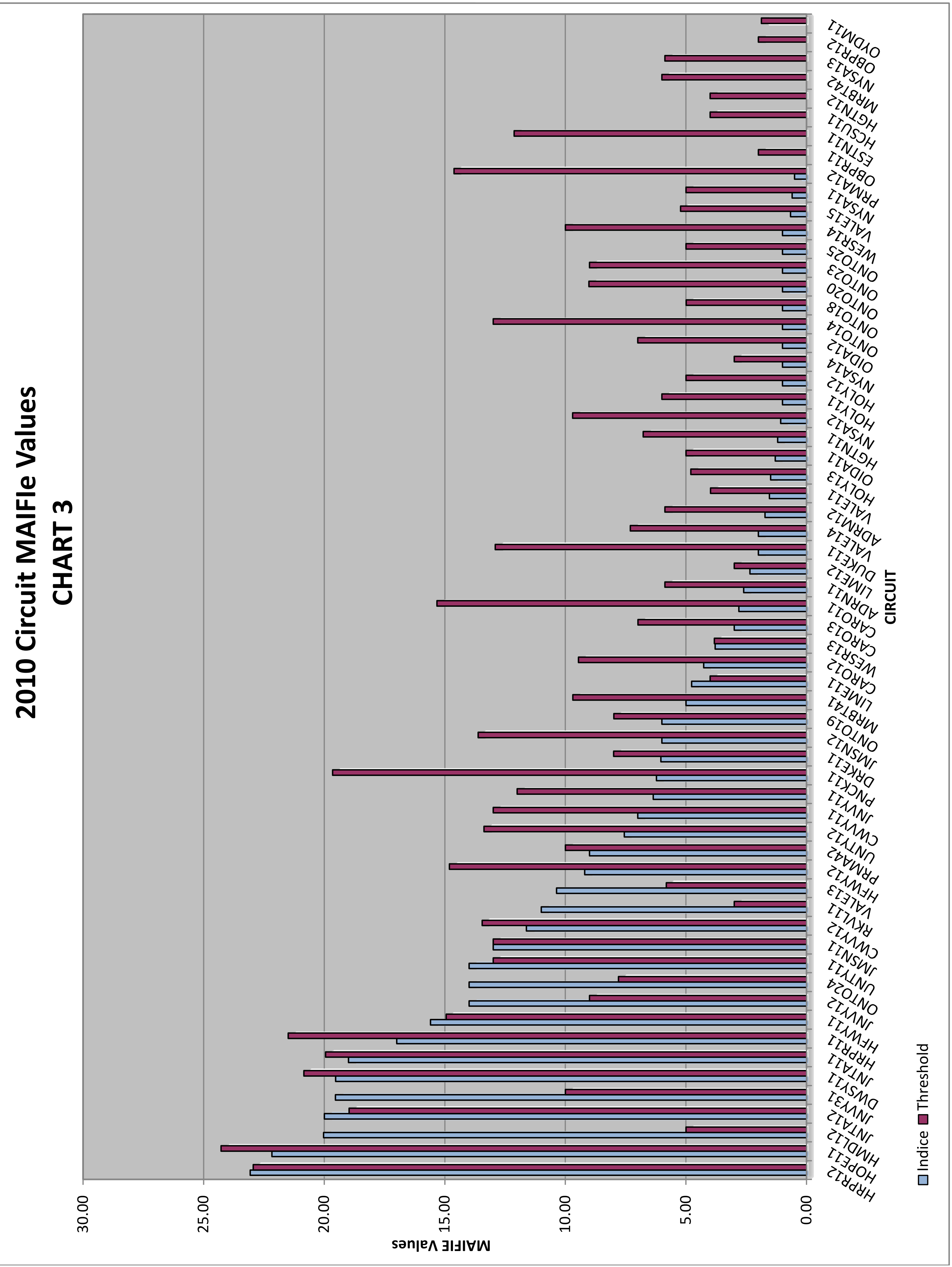
TABLE 4

CIRCUIT	SAIDI	THLD	CIRCUIT	SAIFI	THLD	CIRCUIT	$MAIFI_E$	THLD
RKVL11	54.96	78.56	JNVY31	8.26	30.10	HRPR12	23.07	22.95
CWVY12	50.35	14.19	JNVY11	8.19	19.99	HOPE11	22.17	24.29
JNVY12	44.29	28.11	HRPR11	8.06	9.12	HMDL12	20.03	5.00
JNVY31	38.77	128.22	JNVY12	7.56	8.88	JNTA12	20.00	18.97
JNVY11	36.95	64.44	ESTN11	7.00	6.00	JNVY31	19.54	10.00
HRPR11	26.48	28.69	RKVL11	6.28	10.84	DWSY11	19.53	20.84
LIME12	25.53	12.07	HFWY11	5.14	7.30	JNTA11	19.00	19.95
HFWY11	21.65	11.83	LIME12	5.04	4.80	HRPR11	17.00	21.50
VALE13	19.98	39.28	CARO11	4.47	9.50	HFWY11	15.60	14.95
PNCK11	17.36	18.07	HRPR12	4.37	8.07	JNVY12	14.00	9.00
LIME11	15.90	51.54	DRKE11	4.35	6.49	ONTO24	14.00	7.81
HGTN11	15.86	31.26	JNTA12	4.30	6.02	UNTY11	14.00	13.00
DRKE11	11.67	13.70	OIDA12	4.00	4.00	JMSN11	13.00	13.00
HRPR12	11.13	32.42	PNCK11	3.95	7.77	CWVY12	11.62	13.45
ESTN11	9.72	34.60	JMSN11	3.77	4.40	RKVL11	11.00	3.00
JNTA12	9.38	19.88	VALE13	3.58	3.57	VALE13	10.37	5.82
JMSN11	8.24	10.12	JNTA11	3.42	6.56	HFWY12	9.20	14.81
JNTA11	7.81	25.19	HGTN11	3.29	5.78	PRMA42	9.00	10.00
PRMA42	6.64	25.36	HOLY12	3.27	4.34	UNTY12	7.56	13.38
HOPE11	5.67	12.96	CWVY12	3.17	3.65	CWVY11	7.00	13.00
CARO11	5.48	14.91	PRMA42	3.16	17.64	JNVY11	6.36	12.00
JMSN12	4.90	7.58	HOLY11	3.14	6.79	PNCK11	6.23	19.66
OIDA12	4.90	4.57	HOLY13	2.42	3.58	DRKE11	6.04	8.00
HOLY11	4.48	9.73	HMDL12	2.34	22.56	JMSN12	6.00	13.62
HGTN12	3.86	5.16	HOPE11	2.24	7.44	ONTO19	6.00	7.99
CWVY11	2.98	7.88	LIME11	1.94	16.61	MRBT41	5.00	9.69
VALE14	2.67	20.45	ONTO24	1.90	4.51	LIME11	4.77	4.00
HOLY12	2.62	4.86	VALE14	1.55	5.38	CARO12	4.27	9.46
HMDL12	2.48	34.47	JMSN12	1.48	5.36	WESR13	3.79	3.83
DWSY11	2.37	29.00	DWSY11	1.29	8.77	OBPR11	3.59	2.00
HOLY13	2.24	9.34	MRBT41	1.22	2.89	CARO13	3.00	6.99
ONTO24	2.18	6.73	HGTN12	1.14	2.05	CARO11	2.81	15.33
CARO13	1.75	1.45	CARO12	1.07	7.24	ADRM12	2.61	5.87
ONTO19	1.67	1.54	CARO13	1.07	3.14	LIME12	2.35	3.00
WESR13	1.52	33.48	ONTO23	1.02	17.38	DUKE11	2.00	12.91
NYSA12	1.49	37.43	ONTO14	1.00	7.55	VALE14	2.00	7.31
ONTO14	1.23	17.26	NYSA12	0.95	23.14	ADRN11	1.73	5.87
MRBT41	1.09	11.26	UNTY12	0.82	4.28	VALE11	1.54	3.99
CARO12	0.94	6.86	NYSA11	0.77	4.52	HOLY13	1.49	4.80
PRMA12	0.83	0.00	OIDA11	0.66	9.67	OIDA11	1.30	5.00
VALE11	0.75	4.37	ONTO19	0.53	1.00	HGTN11	1.20	6.78
OYDM11	0.67	14.36	PRMA12	0.50	14.63	NYSA12	1.08	9.70
ONTO23	0.58	50.45	WESR13	0.47	0.00	HOLY11	1.00	6.00
VALE15	0.54	7.35	WESR14	0.35	0.00	HOLY12	1.00	5.00
WESR14	0.52	56.58	VALE11	0.31	3.87	NYSA14	1.00	3.00
ADRN12	0.50	95.64	CWVY11	0.27	3.21	OIDA12	1.00	7.00
UNTY11	0.47	15.03	OYDM11	0.27	5.70	ONTO14	1.00	13.00
NYSA11	0.46	4.20	VALE15	0.23	4.26	ONTO18	1.00	5.00
OIDA11	0.41	17.65	ONTO20	0.21	1.40	ONTO20	1.00	9.03
ONTO20	0.33	3.75	NYSA13	0.16	15.90	ONTO23	1.00	9.00
UNTY12	0.31	10.67	UNTY11	0.16	5.97	ONTO25	1.00	5.00
NYSA13	0.22	16.43	HFWY12	0.11	11.48	WESR14	1.00	10.00
ONTO18	0.21	2.96	ADRN12	0.11	8.00	VALE15	0.67	5.23
HFWY12	0.18	26.73	ADRN11	0.10	0.00	NYSA11	0.60	5.00
ADRN11	0.15	28.37	ONTO18	0.10	3.32	ESTN11	0.00	12.13
MRBT42	0.15	25.14	MRBT42	0.10	3.32	HCSU11	0.00	4.00
ONTO25	0.14	0.66	ONTO25	0.09	1.33	HGTN12	0.00	4.00
NYSA14	0.05	8.58	NYSA14	0.03	5.62	MRBT42	0.00	6.00
DUKE11	0.00	14.12	DUKE11	0.00	7.09	NYSA13	0.00	5.87
HCSU11	0.00	5.37	HCSU11	0.00	3.00	OBPR12	0.00	2.00
OBPR11	0.00	0.00	OBPR11	0.00	0.00	OYDM11	0.00	1.88
OBPR12	0.00	1.00	OBPR12	0.00	1.00	PNCK12	0.00	14.00
PNCK12	0.00	23.00	PNCK12	0.00	5.50	PRMA12	0.00	0.00

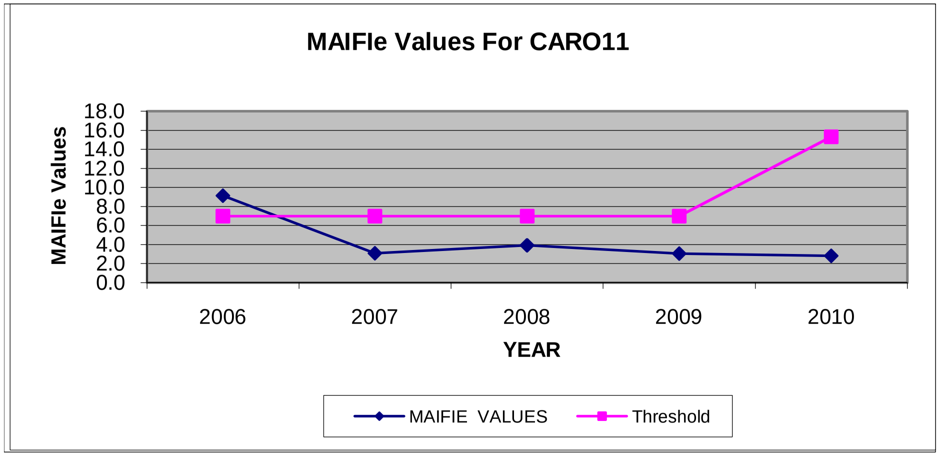

2010 Circuit SAIDI Values
CHART 1
SAIDI Values
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
CIRCUIT
Indice Value
Threshold
RKVL11
CWVY12
JNVY12
JNVY31
JNVY11
HRPR11
LIME12
HFWY11
VALE13
PNCK11
LIME11
HGTN11
DRKE11
HRPR12
ESTN11
JNTA12
JMSN11
JNTA11
PRMA42
HOPE11
CARO11
JMSN12
OIDA12
HOLY11
HGTN12
CWVY11
VALE14
HOLY12
HMDL12
DWSY11
HOLY13
ONTO24
CARO13
ONTO19
WESR13
NYSA12
ONTO14
MRBT41
CARO12
PRMA12
VALE11
OYDM11
ONTO23
VALE15
WESR14
ADRN12
UNTY11
NYSA11
OIDA11
ONTO20
UNTY12
NYSA13
ONTO18
HFWY12
ADRN11
MRBT42
ONTO25
NYSA14
DUKE11
HCSU11
OBPR11
OBPR12

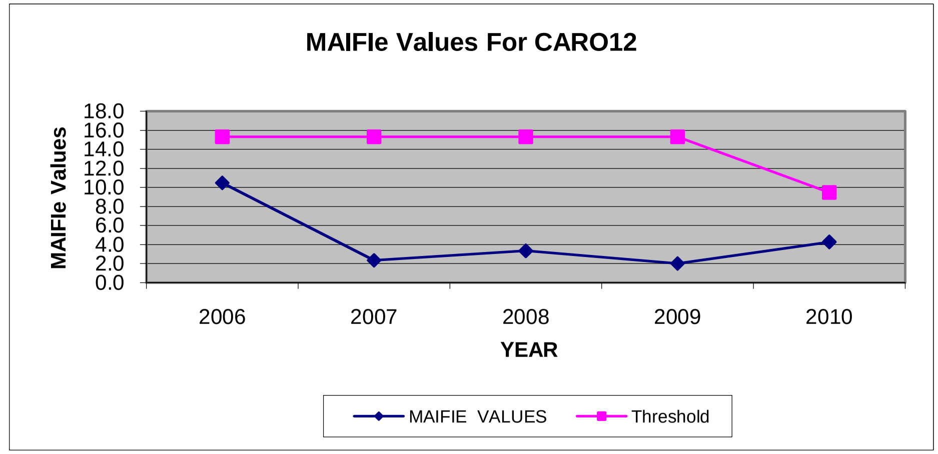
2010 Circuit SAIFI Values
CHART 2

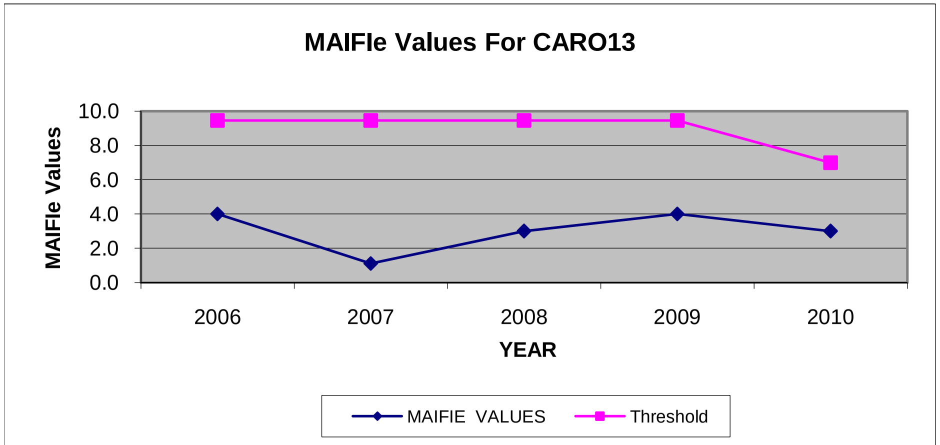


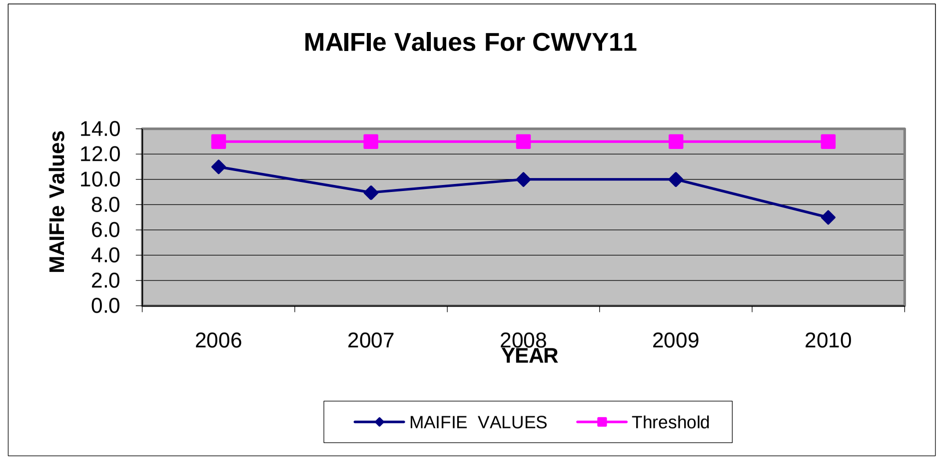

2010 Circuit MAIFIe Values
CHART 3
MAIFIE Values
30.00
25.00
20.00
15.00
10.00
5.00
0.00
HRPR12
HOPE11
HMDL12
JNTA12
JNVY31
DWSY11
JNTA11
HRPR11
HFWY11
JNVY12
ONTO24
UNTY11
JMSN11
CWVY12
RKVL11
VALE13
HFWY12
PRMA42
UNTY12
CWVY11
JNVY11
PNCK11
DRKE11
JMSN12
ONTO19
MRBT41
LIME11
CARO12
WESR13
CARO13
CARO11
ADRN11
LIME12
DUKE11
VALE14
ADRM12
VALE11
HOLY13
OIDA11
HGTN11
NYSA12
HOLY11
HOLY12
NYSA14
OIDA12
ONTO14
ONTO18
ONTO20
ONTO23
ONTO25
WESR14
VALE15
NYSA11
PRMA12
OBPR11
ESTN11
HCSU11
HGTN12
MRBT42
NYSA13
OBPR12
OYDM11
CIRCUIT
Indice
Threshold

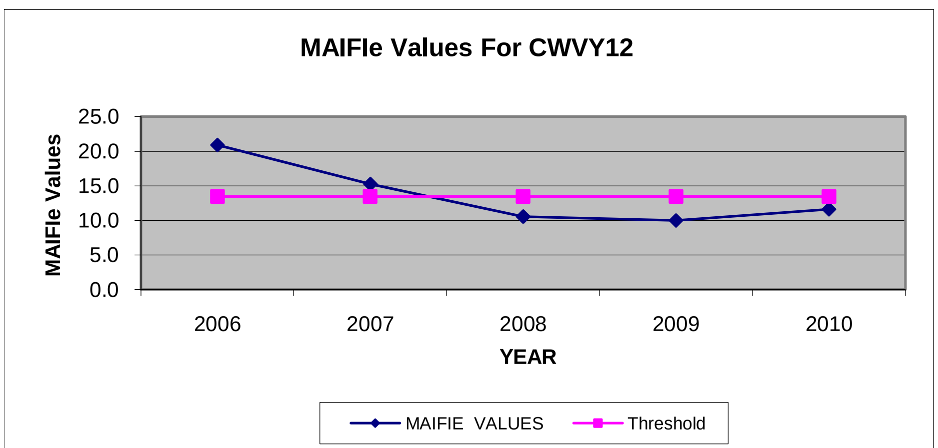
CHARTS - Circuit MAIFIe Values

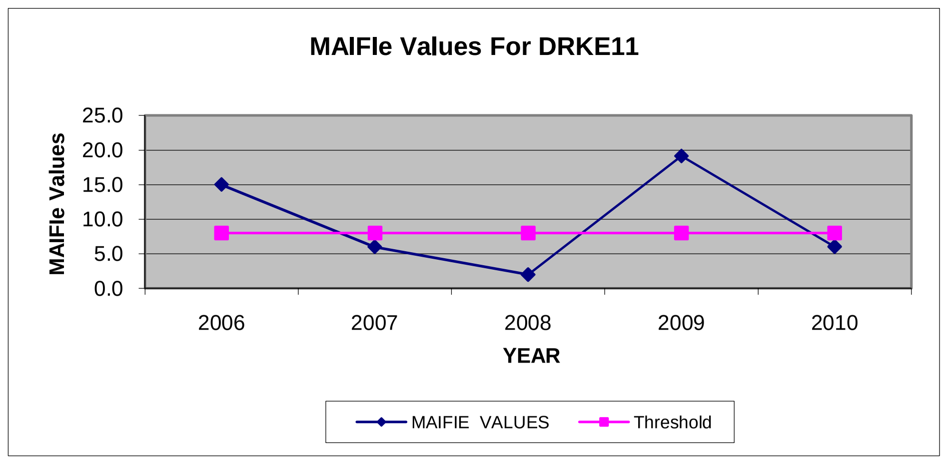


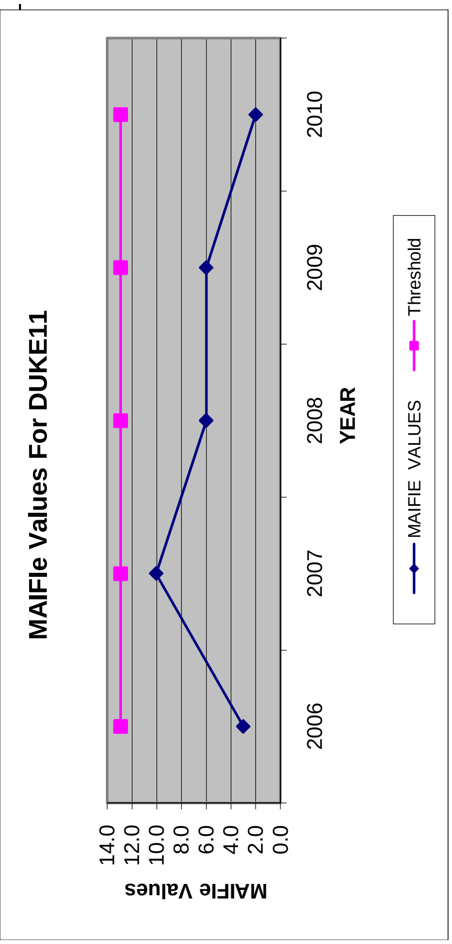


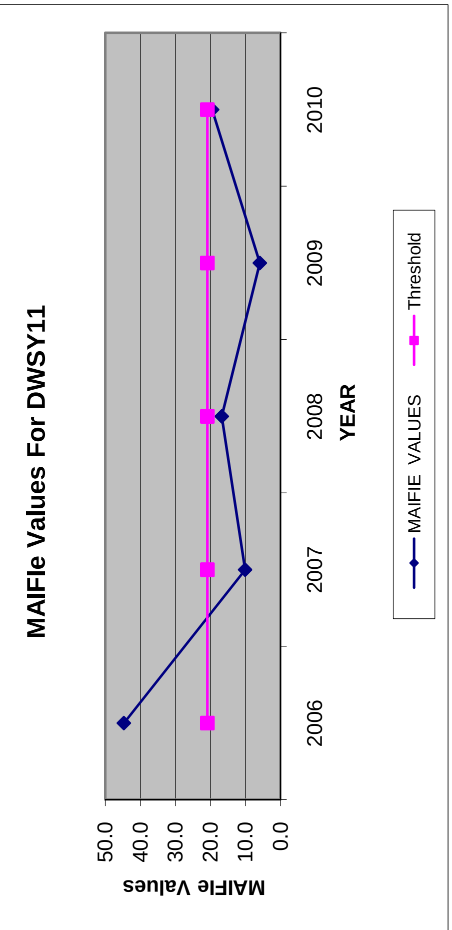


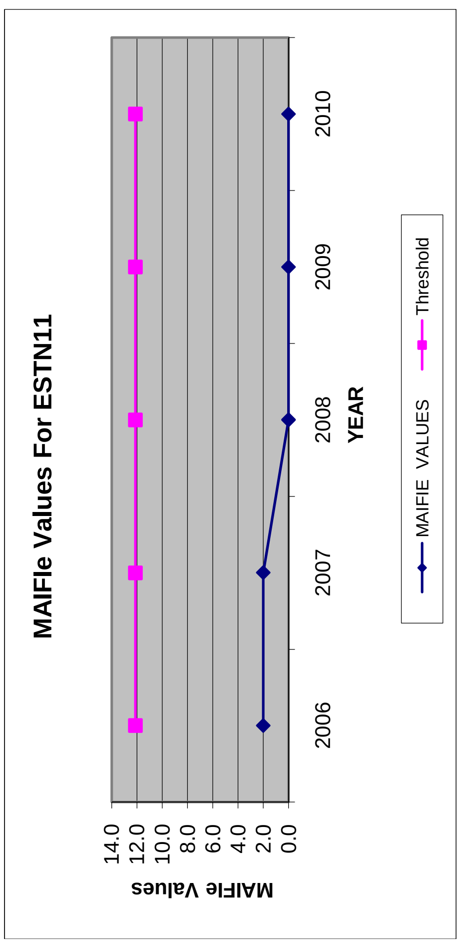


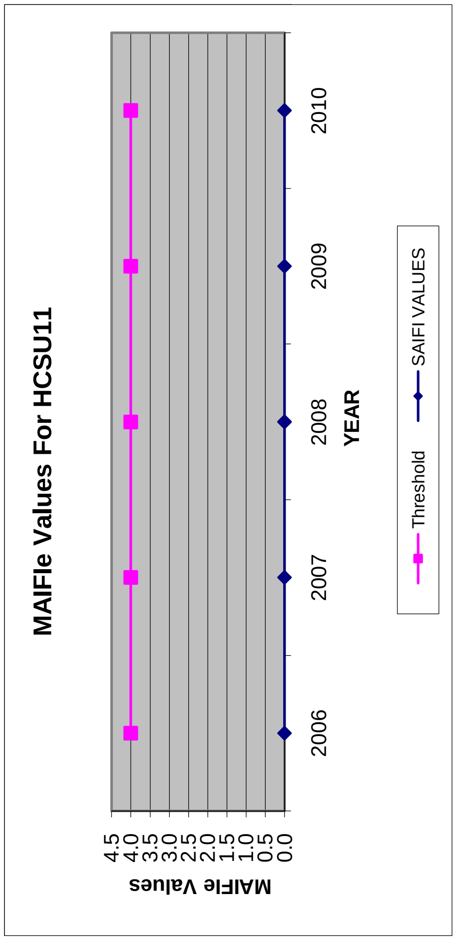


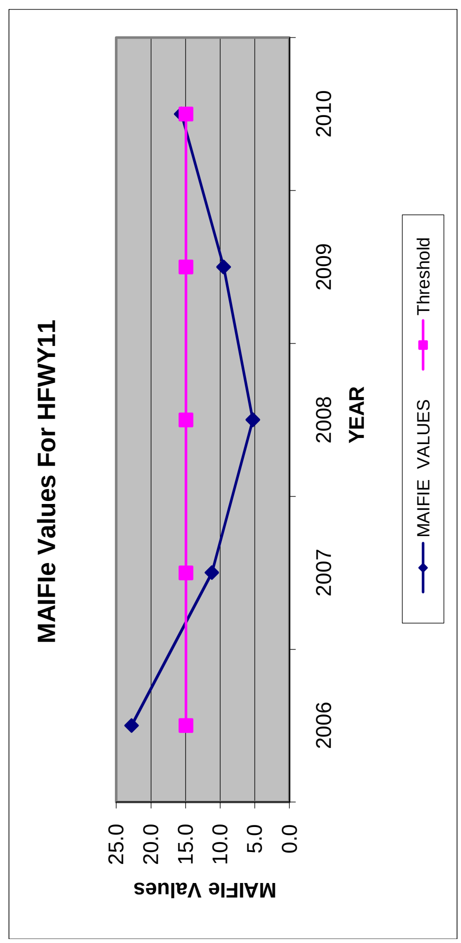


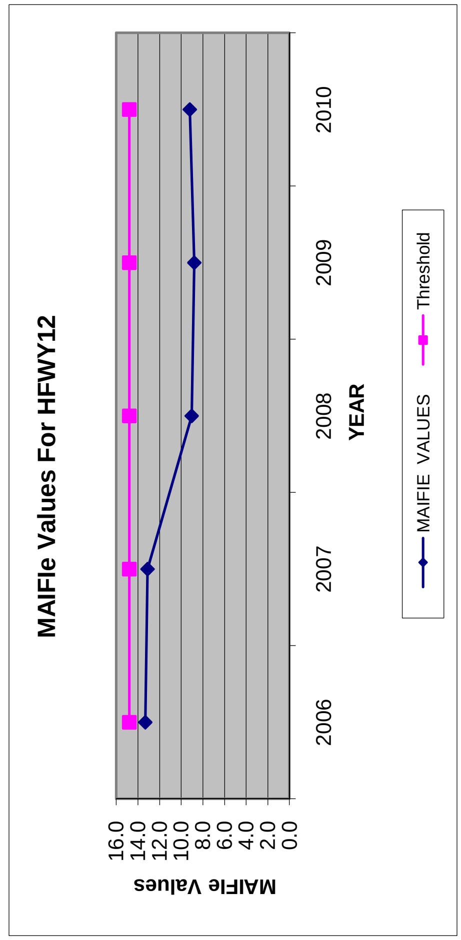

MAIFIe Values For DUKE11
MAIFIe Values
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For DWSY11
MAIFIe Values
50.0
40.0
30.0
20.0
10.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For ESTN11
MAIFIe Values
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HCSU11
MAIFIe Values
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
Threshold
SAIFI VALUES


MAIFIe Values For HFWY11
MAIFIe Values
25.0
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HFWY12
MAIFIe Values
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14.0
12.0
10.0
8.0
6.0
4.0
2.0
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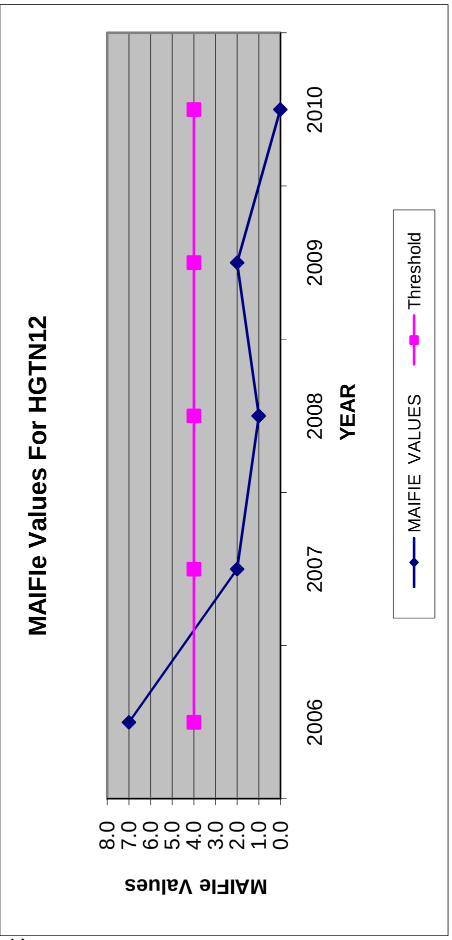
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HGTN12
MAIFIe Values
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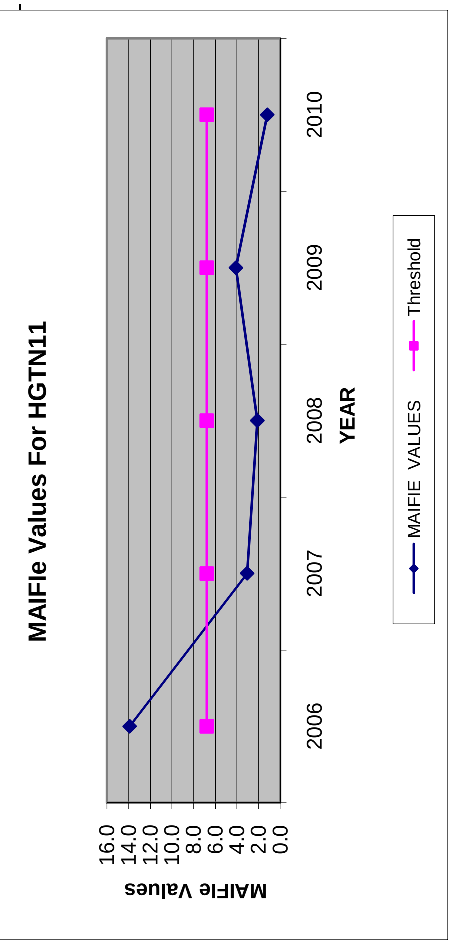
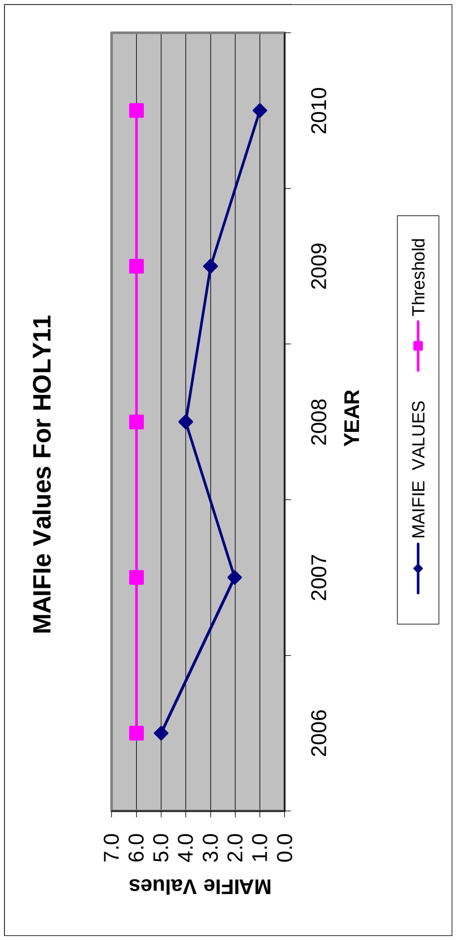
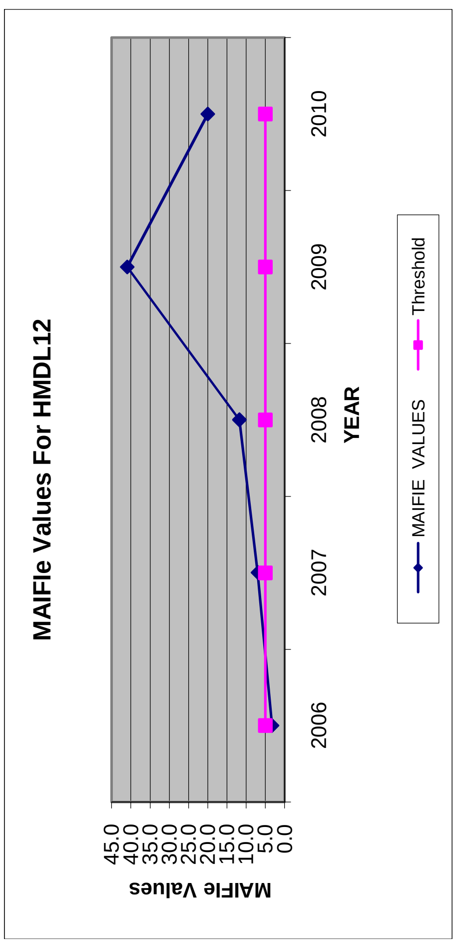
2006 2007 2008 2009 2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HGTN11
MAIFIe Values
16.0 14.0 12.0 10.0 8.0 6.0 4.0 2.0 0.0
2006 2007 2008 2009 2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HOLY11
MAIFIe Values
7.0 6.0 5.0 4.0 3.0 2.0 1.0 0.0
2006 2007 2008 2009 2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HMDL12
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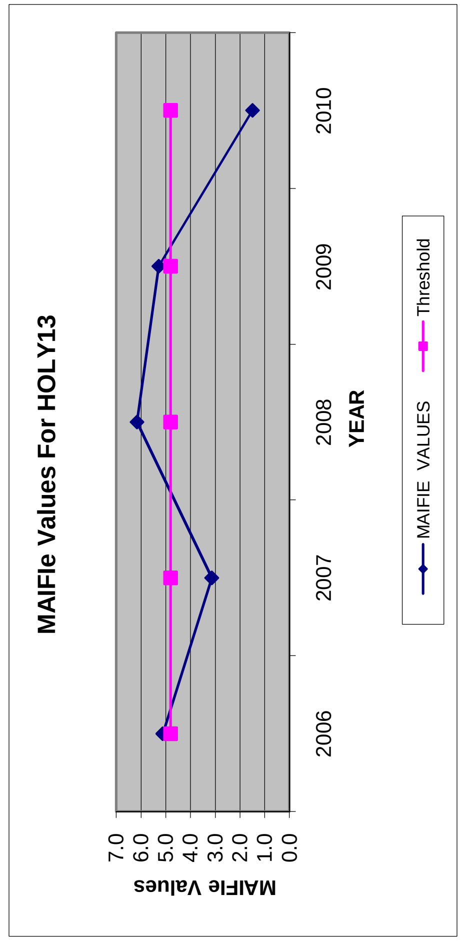
2006 2007 2008 2009 2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HOLY13
MAIFIe Values
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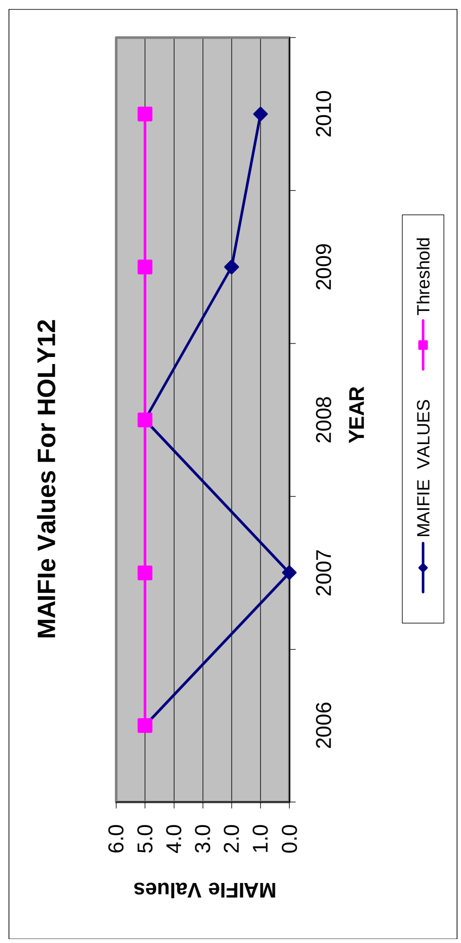
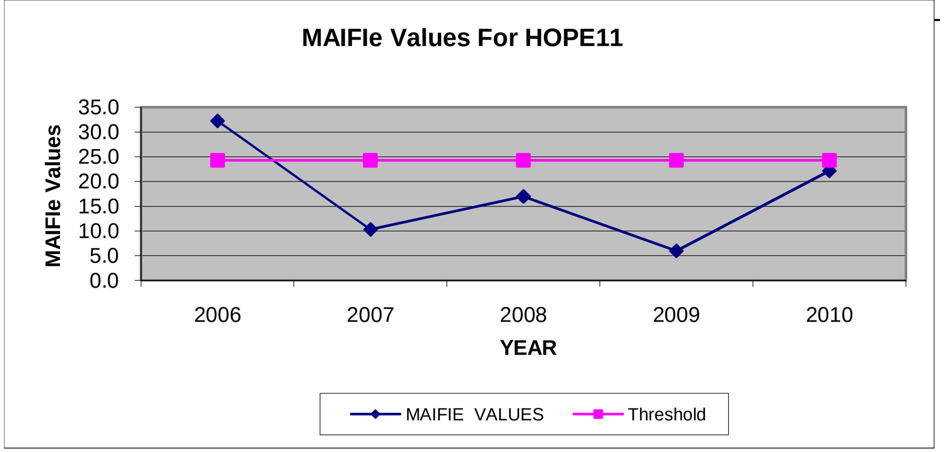
2006 2007 2008 2009 2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HOLY12
MAIFIe Values
6.0 5.0 4.0 3.0 2.0 1.0 0.0
2006 2007 2008 2009 2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HOPE11
MAIFIe Values
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30.0
25.0
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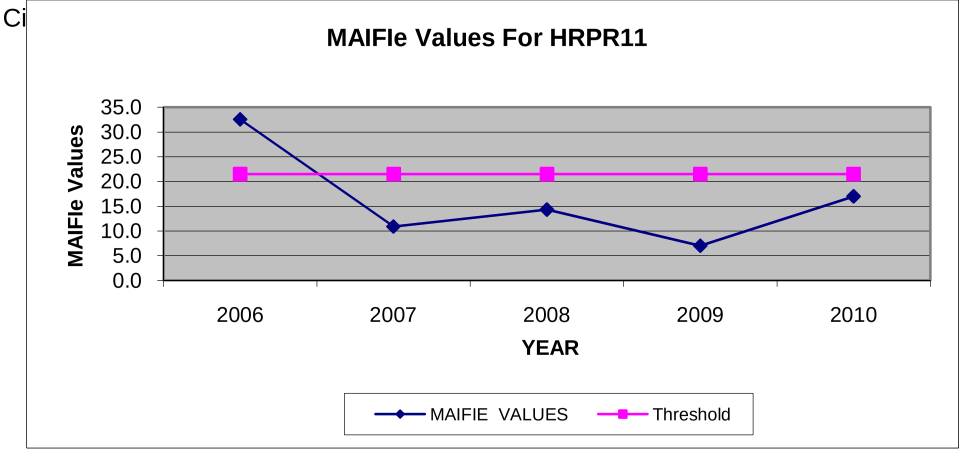
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HRPR11
MAIFIe Values
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30.0
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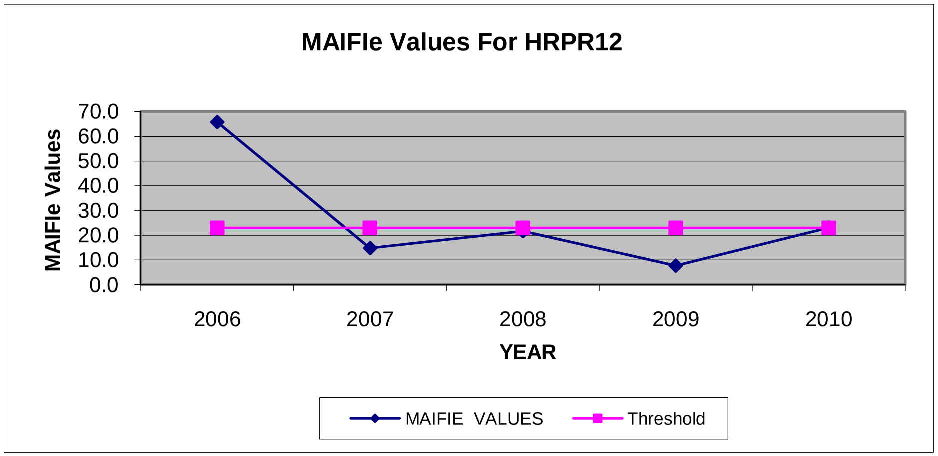
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For HRPR12
MAIFIe Values
70.0
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50.0
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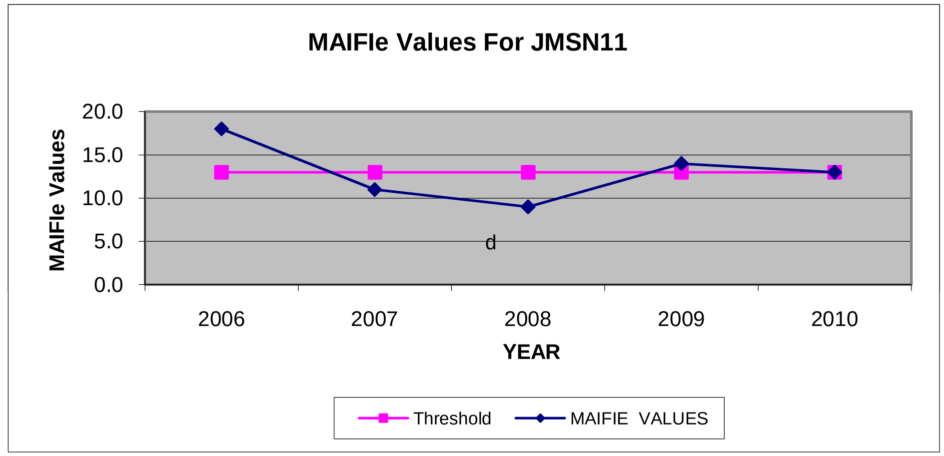
30.0
20.0
10.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For JMSN11
MAIFIe Values
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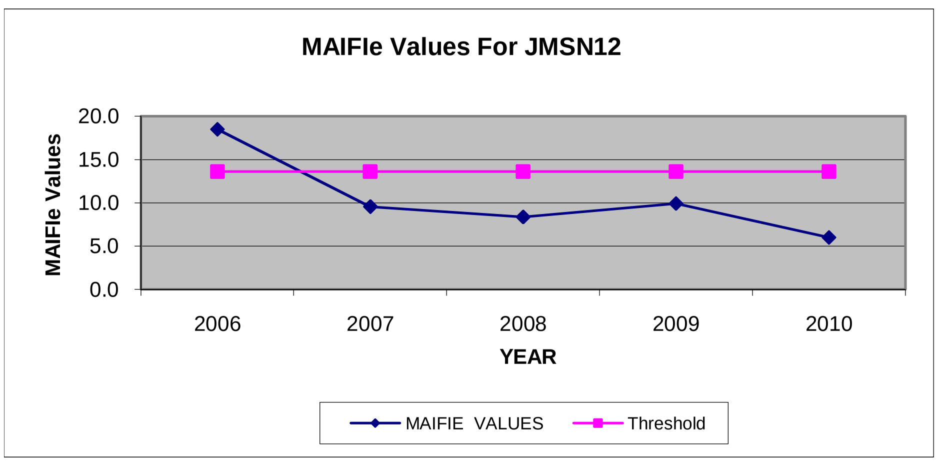
15.0
10.0
5.0
0.0
d
2006
2007
2008
2009
2010
YEAR
Threshold
MAIFIE VALUES


MAIFIe Values For JMSN12
MAIFIe Values
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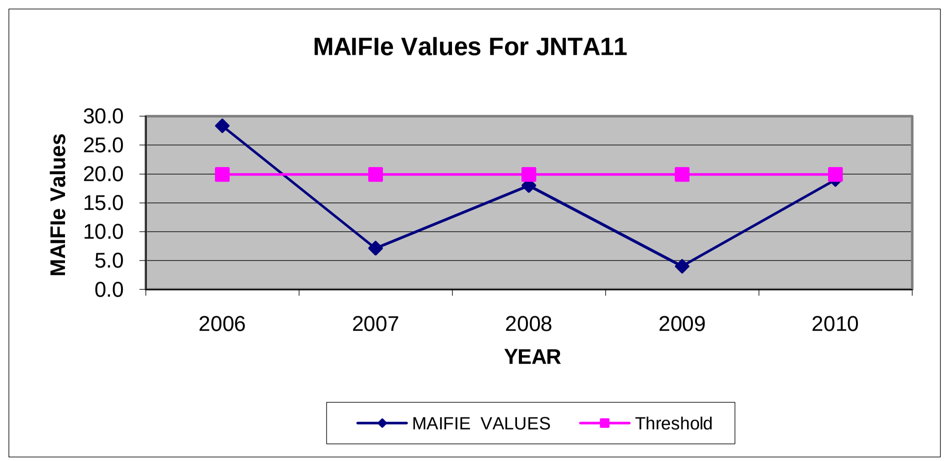
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold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MAIFIe Values
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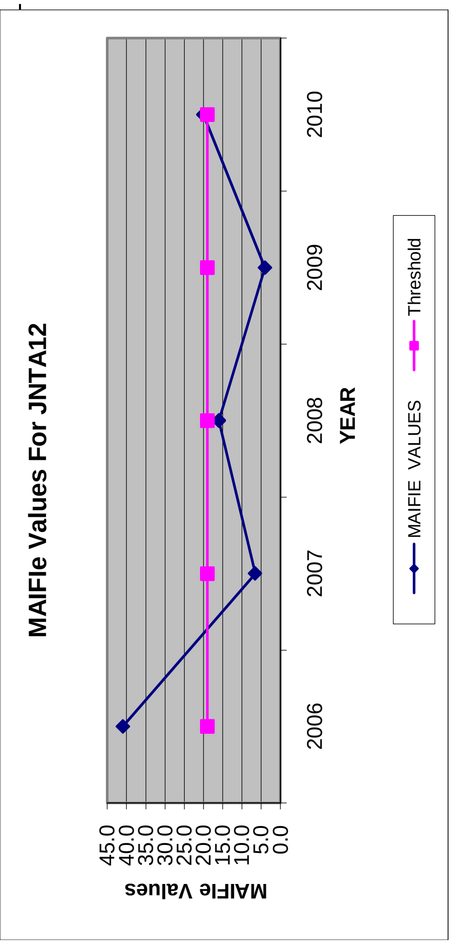
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold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MAIFIe Values
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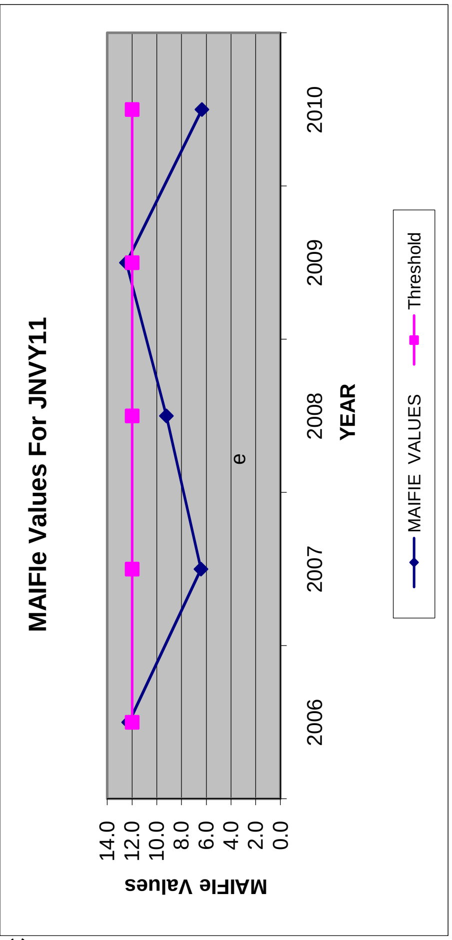
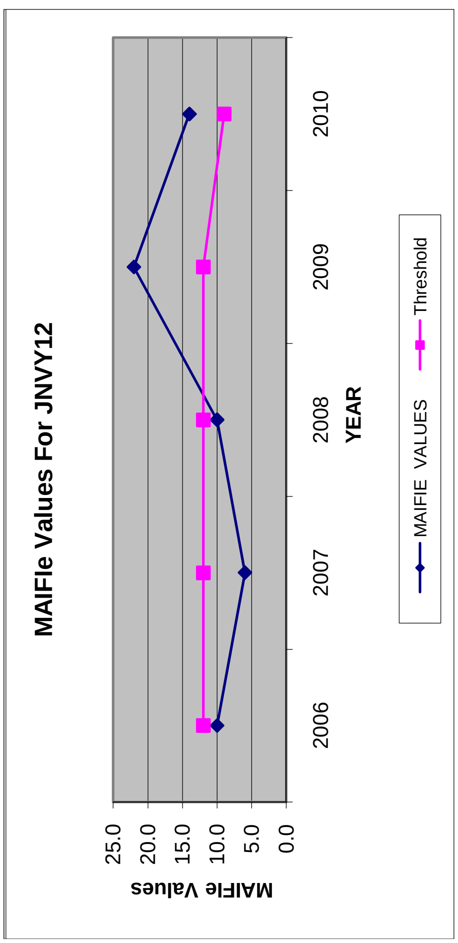
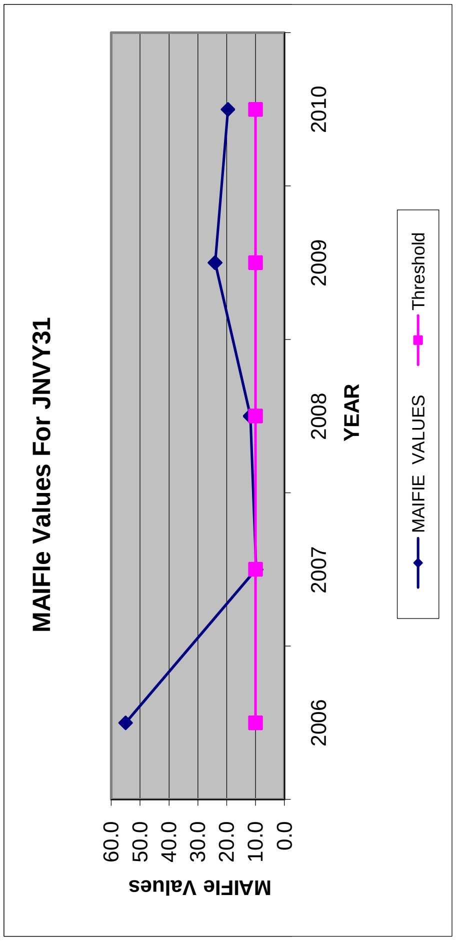
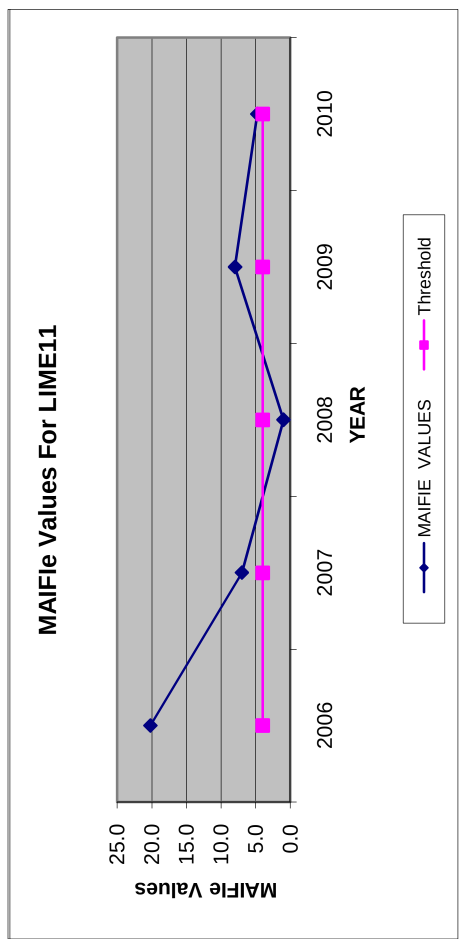
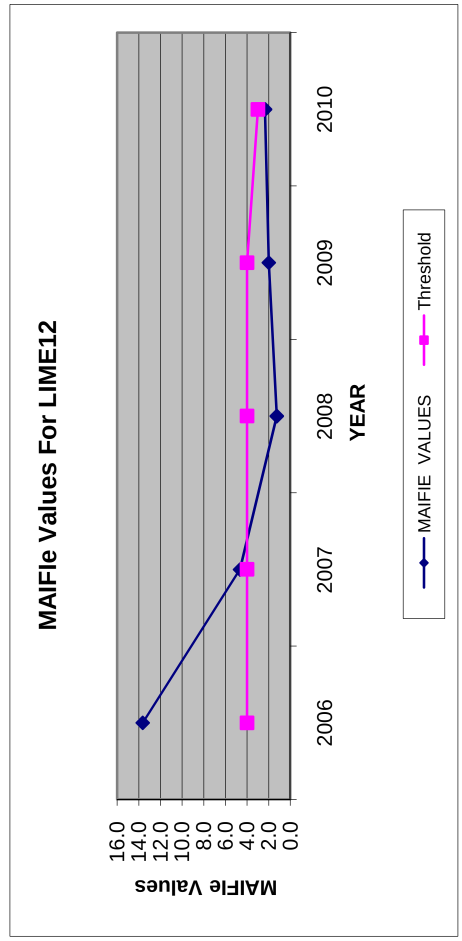
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

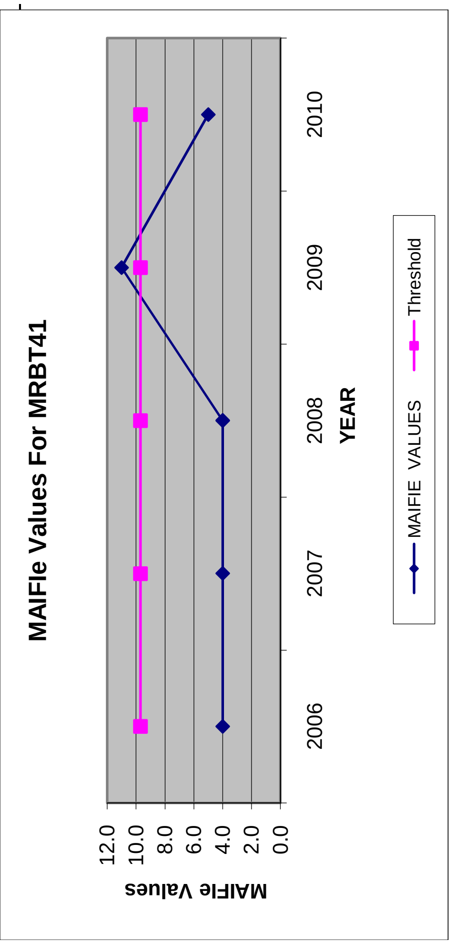

MAIFIe Values For JNVY11
MAIFIe Values
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

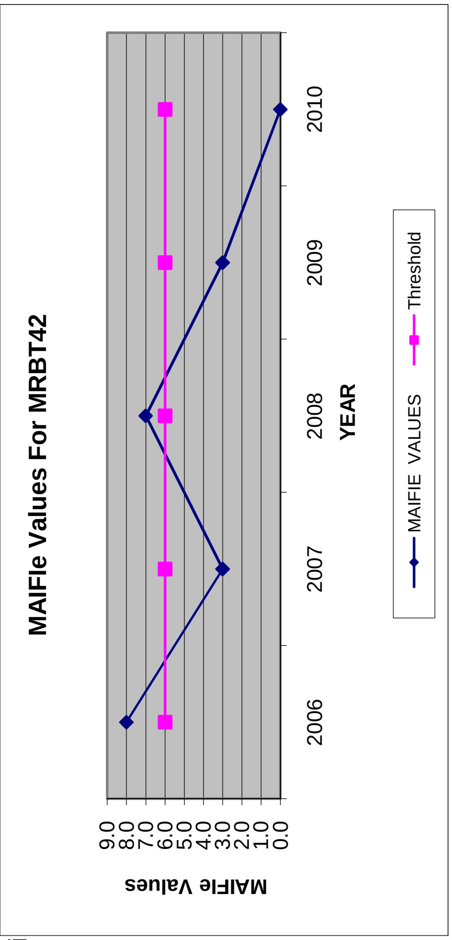

MAIFIe Values For JNVY12
MAIFIe Values
25.0
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

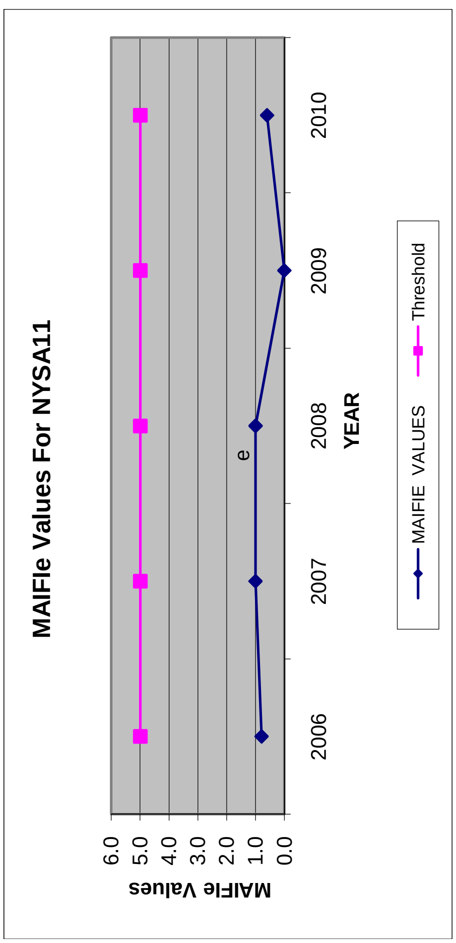

MAIFIe Values For JNVY31
MAIFIe Values
60.0
50.0
40.0
30.0
20.0
10.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

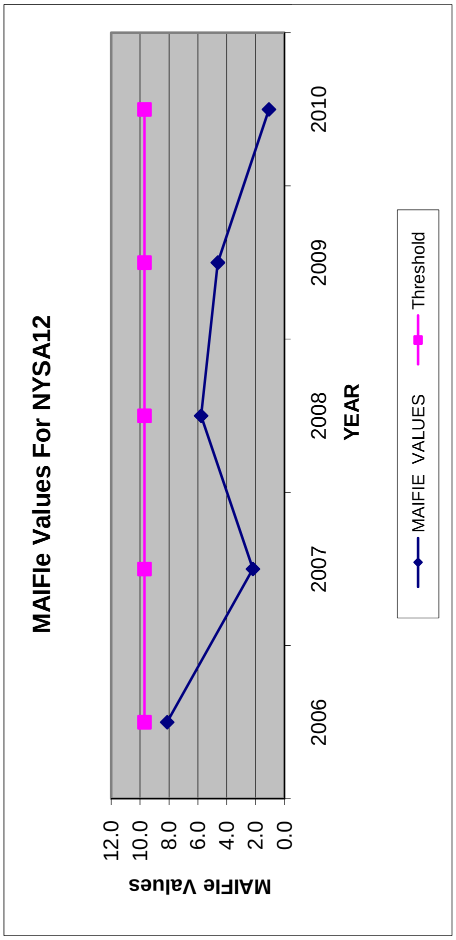

MAIFIe Values For LIME11
MAIFIe Values
25.0
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

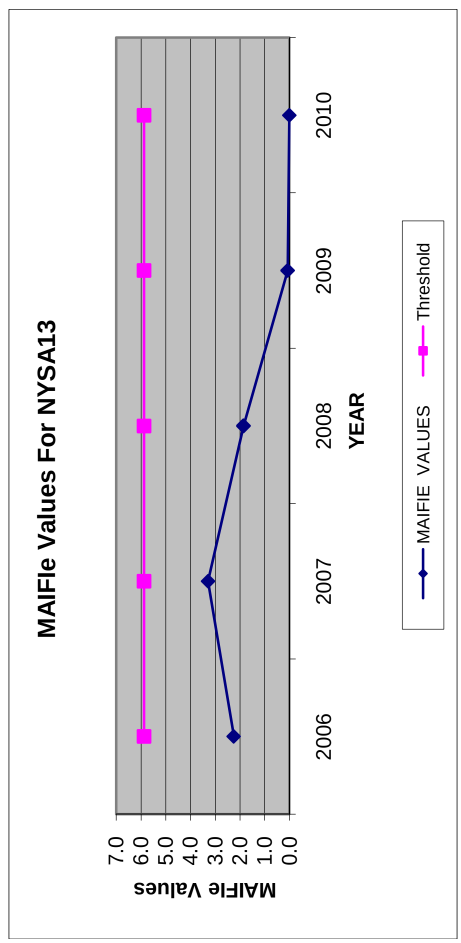

MAIFIe Values For LIME12
MAIFIe Values
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

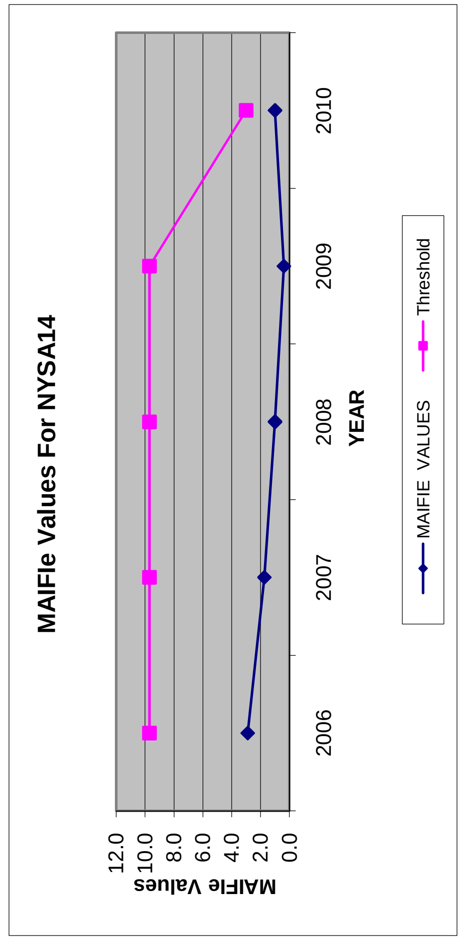

MAIFIe Values For MRBT41
MAIFIe Values
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

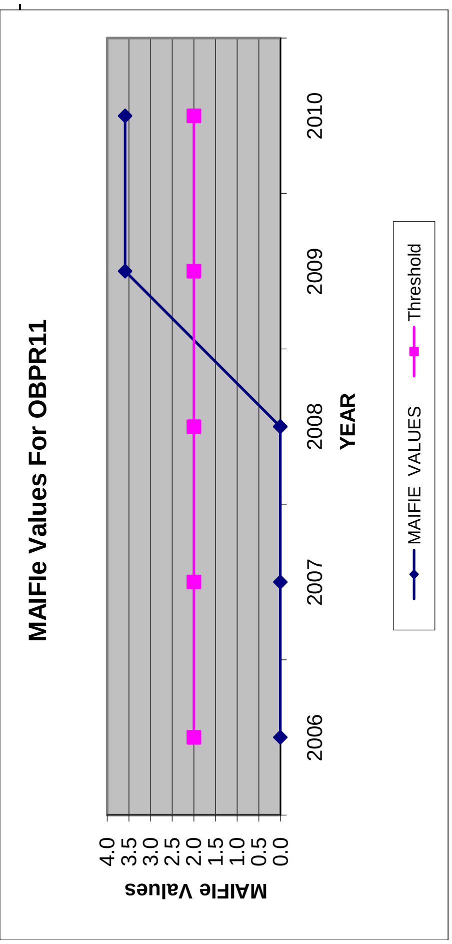

MAIFIe Values For MRBT42
MAIFIe Values
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

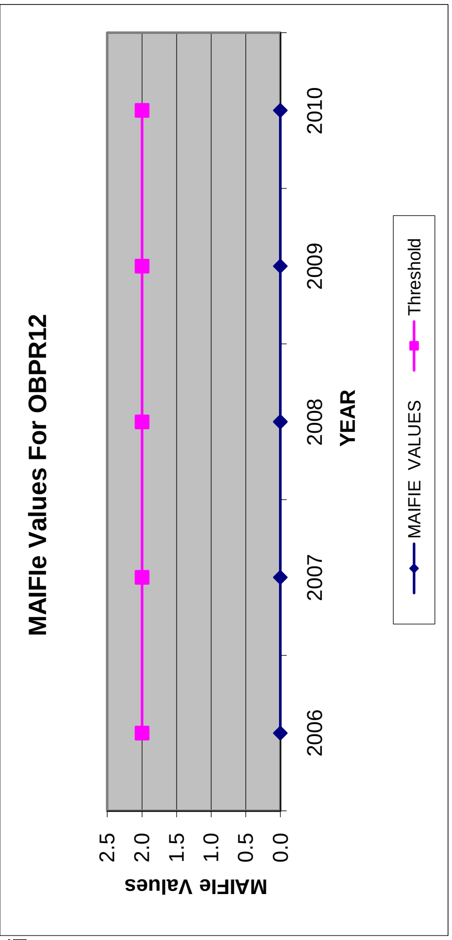

MAIFIe Values For NYSA11
MAIFIe Values
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

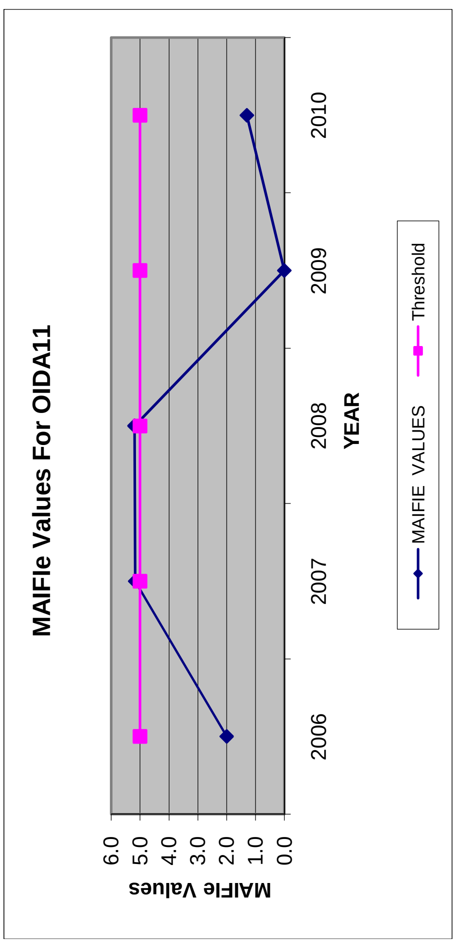

MAIFIe Values For NYSA12
MAIFIe Values
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

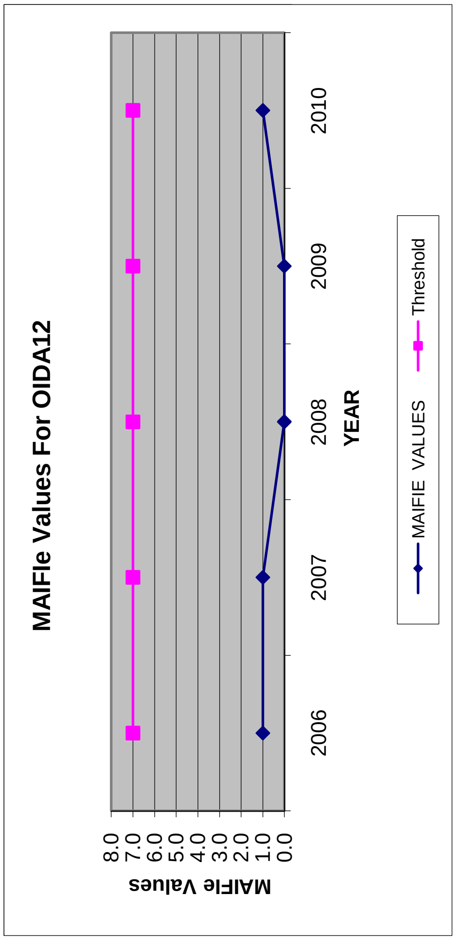

MAIFIe Values For NYSA13
MAIFIe Values
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

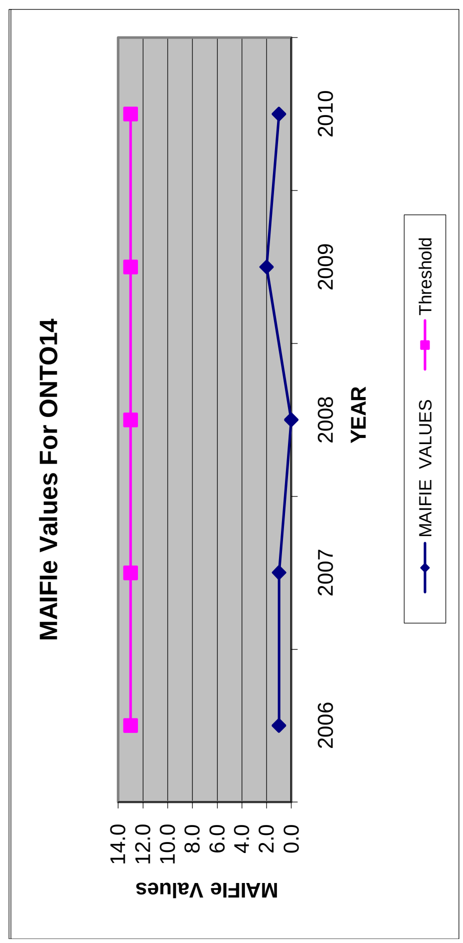

MAIFIe Values For NYSA14
MAIFIe Values
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

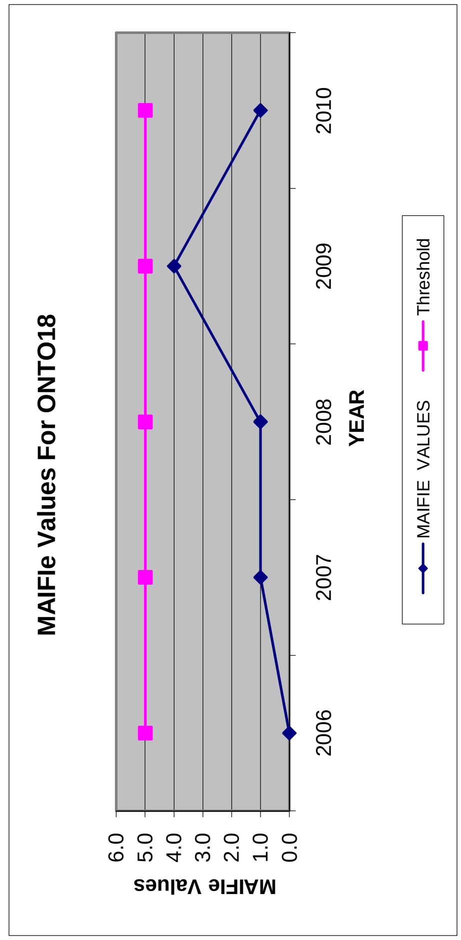

MAIFIe Values For OBPR11
MAIFIe Values
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

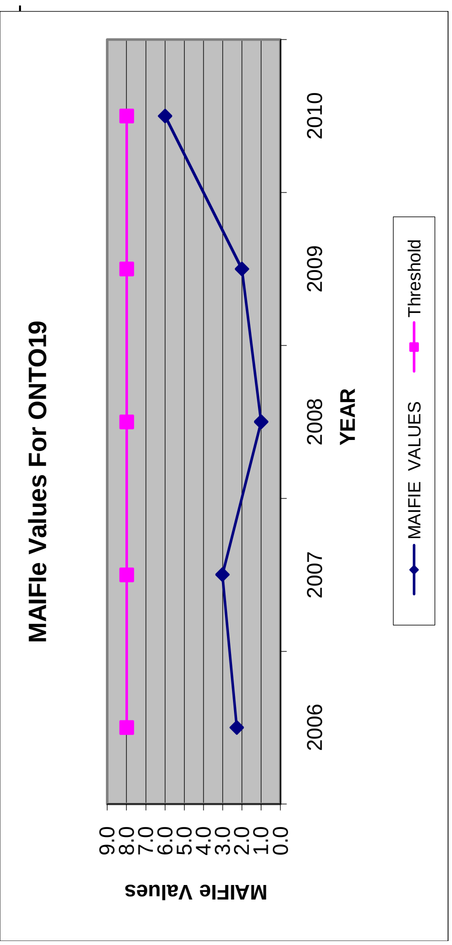

MAIFIe Values For OBPR12
MAIFIe Values
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

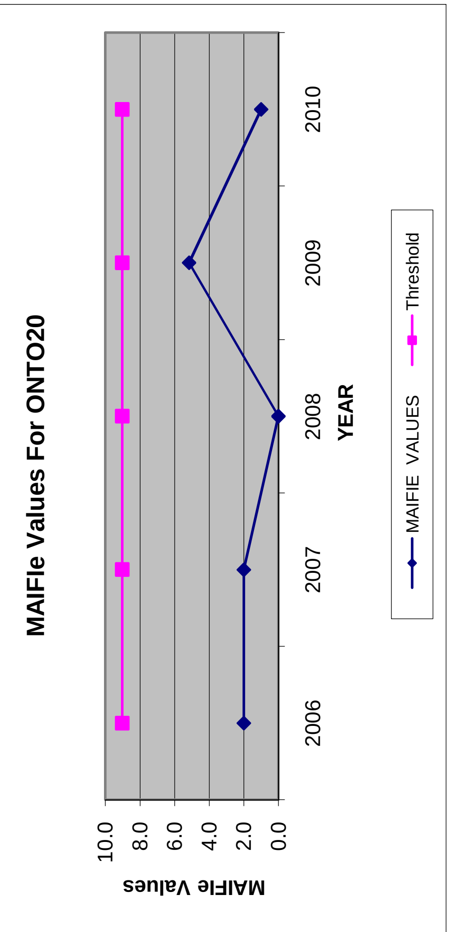

MAIFIe Values For OIDA11
MAIFIe Values
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

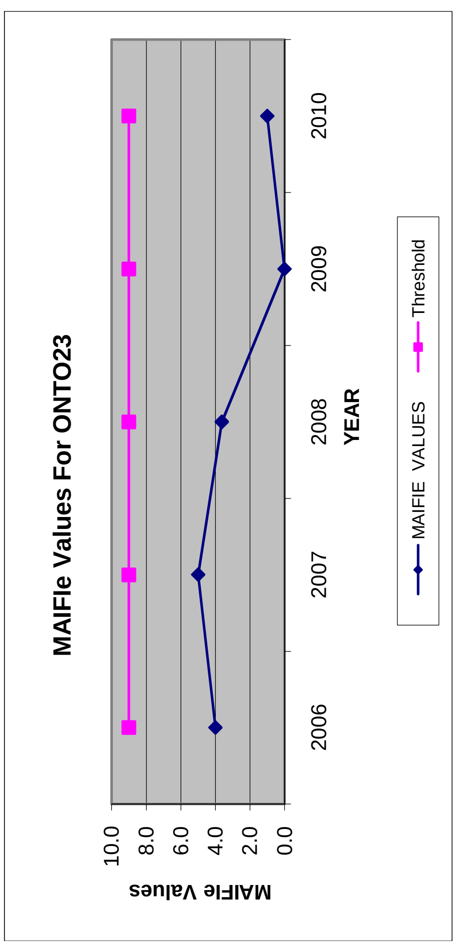

MAIFIe Values For OIDA12
MAIFIe Values
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

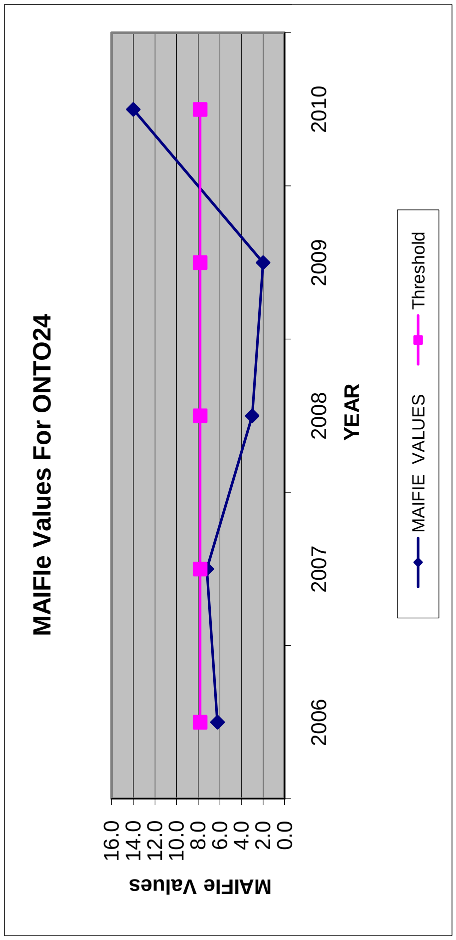

MAIFIe Values For ONTO14
MAIFIe Values
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

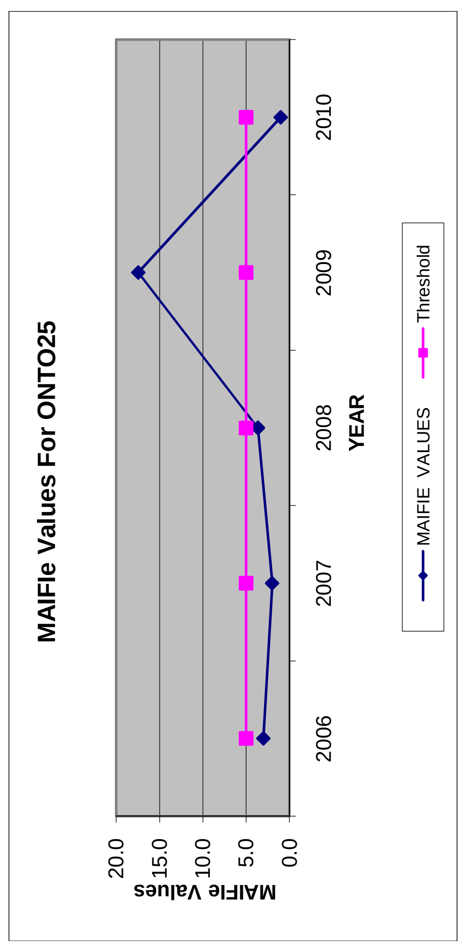

MAIFIe Values For ONTO18
MAIFIe Values
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

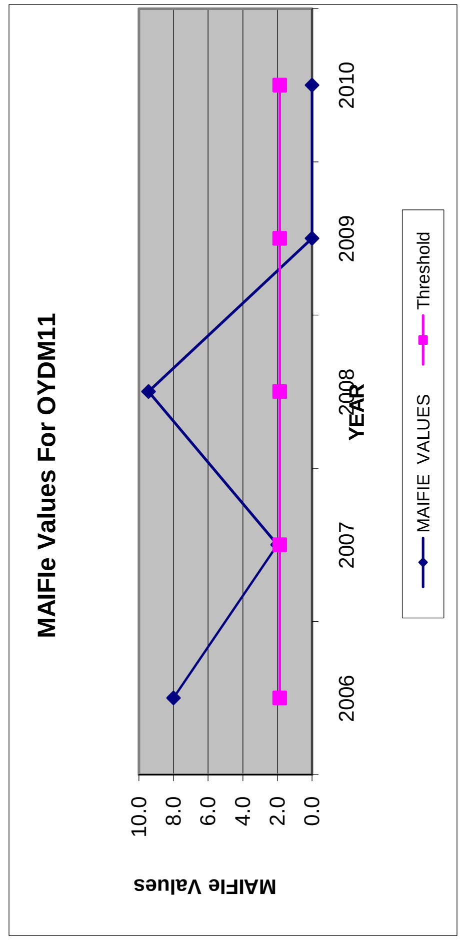

MAIFIe Values For ONTO19
MAIFIe Values
YEAR
2006
2007
2008
2009
2010
MAIFIE VALUES
Threshold

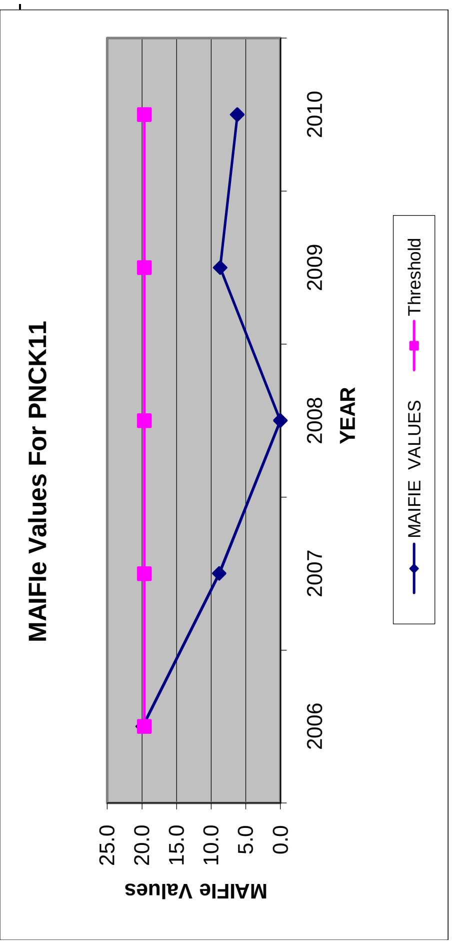

MAIFIe Values For ONTO20
MAIFIe Values
YEAR
2006
2007
2008
2009
2010
MAIFIE VALUES
Threshold

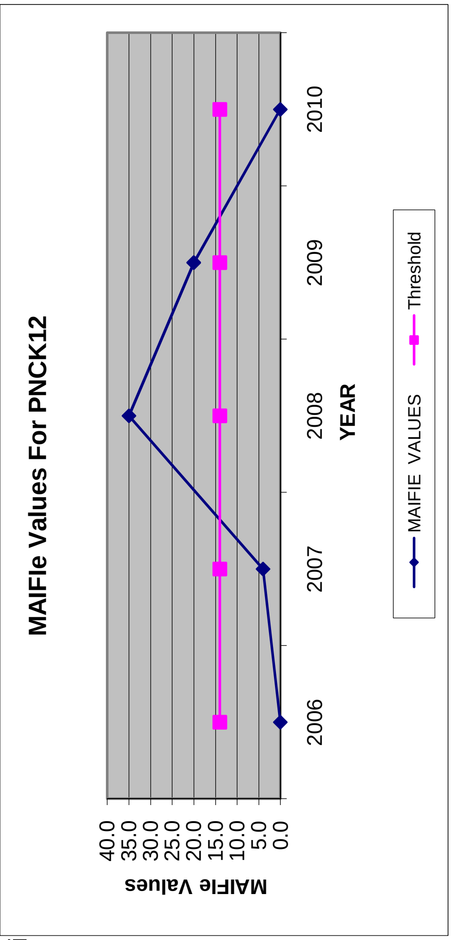

MAIFIe Values For ONTO23
MAIFIe Values
YEAR
2006
2007
2008
2009
2010
MAIFIE VALUES
Threshold

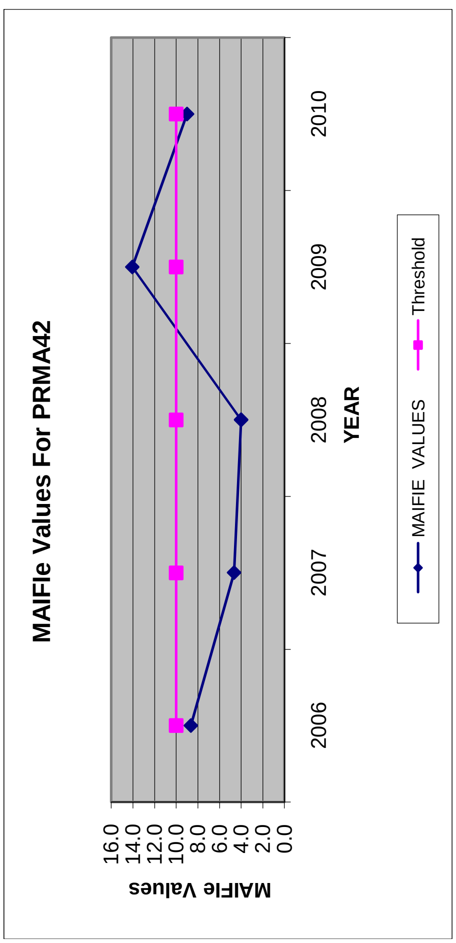

MAIFIe Values For ONTO24
MAIFIe Values
YEAR
2006
2007
2008
2009
2010
MAIFIE VALUES
Threshold

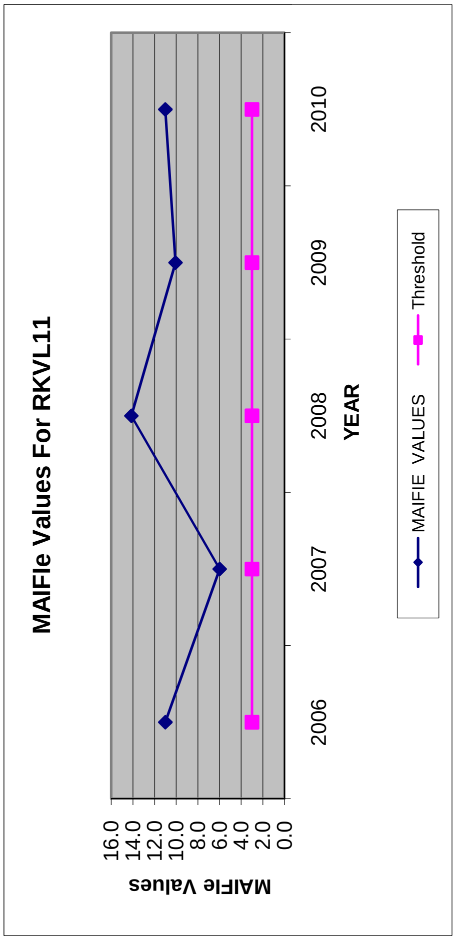

MAIFIe Values For ONTO25
MAIFIe Values
YEAR
2006
2007
2008
2009
2010
MAIFIE VALUES
Threshold

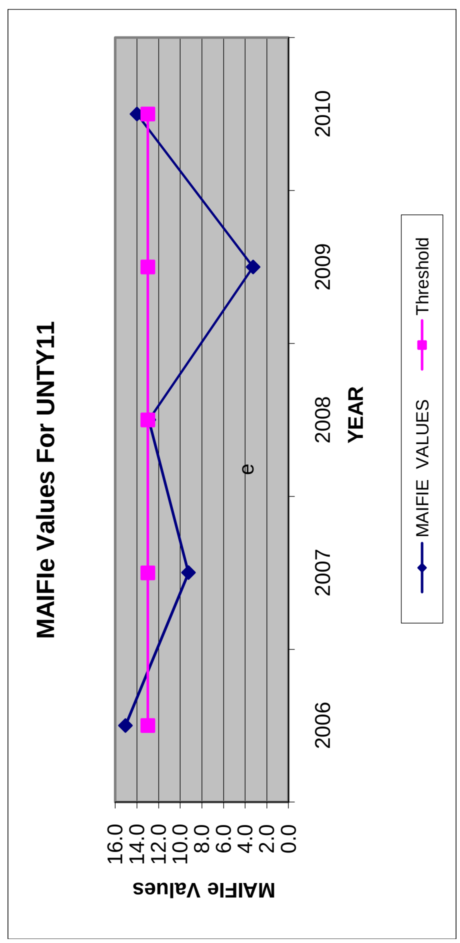

MAIFIe Values For OYDM11
MAIFIe Values
YEAR
2006
2007
2008
2009
2010
MAIFIE VALUES
Threshold

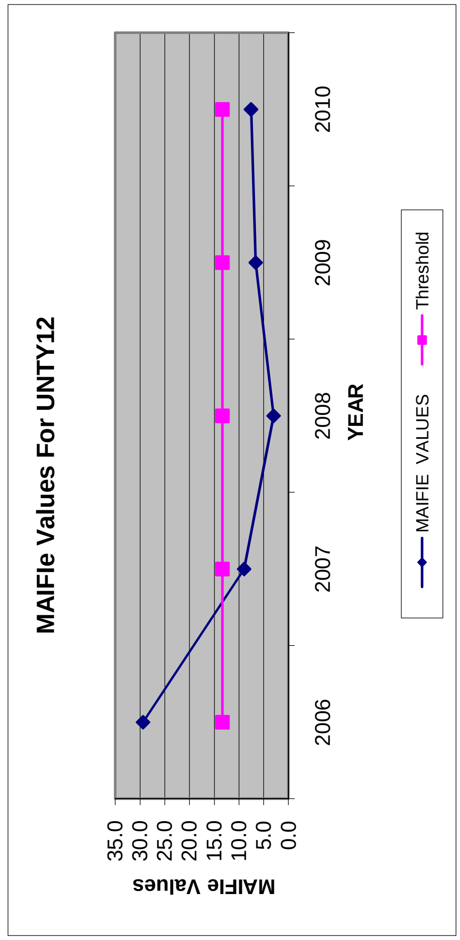

MAIFIe Values For PNCK11
MAIFIe Values
25.0
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

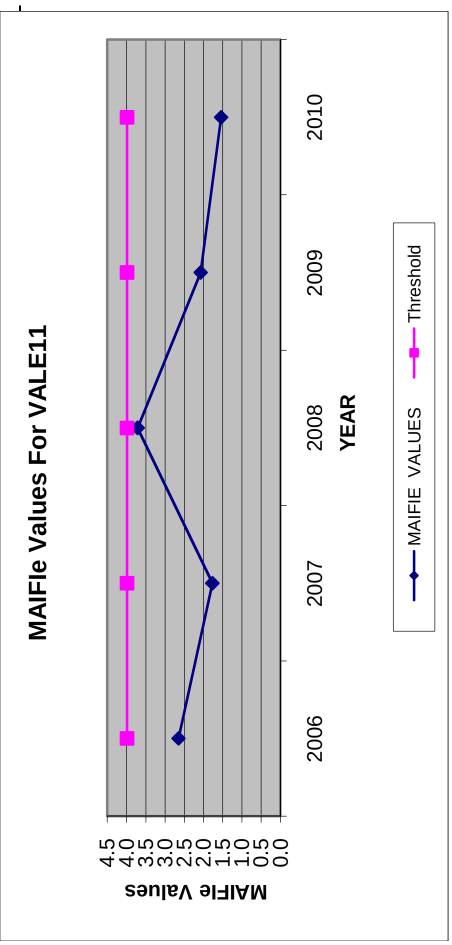

MAIFIe Values For PNCK12
MAIFIe Values
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

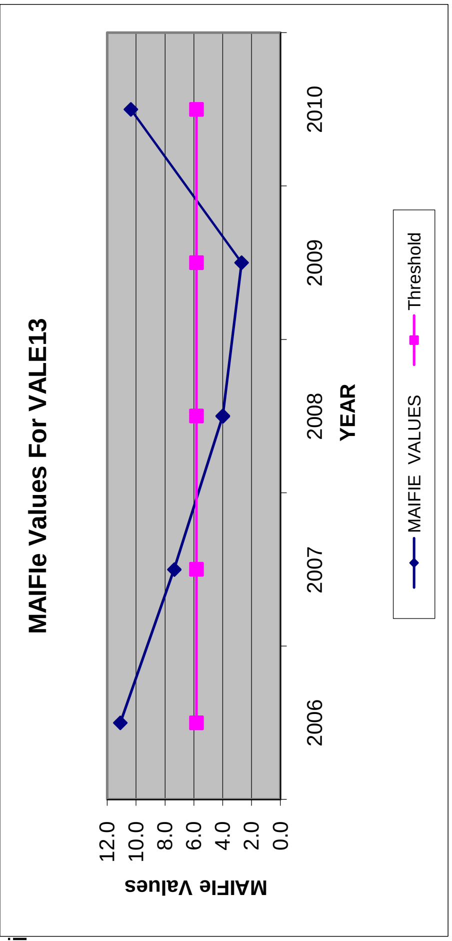

MAIFIe Values For PRMA42
MAIFIe Values
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

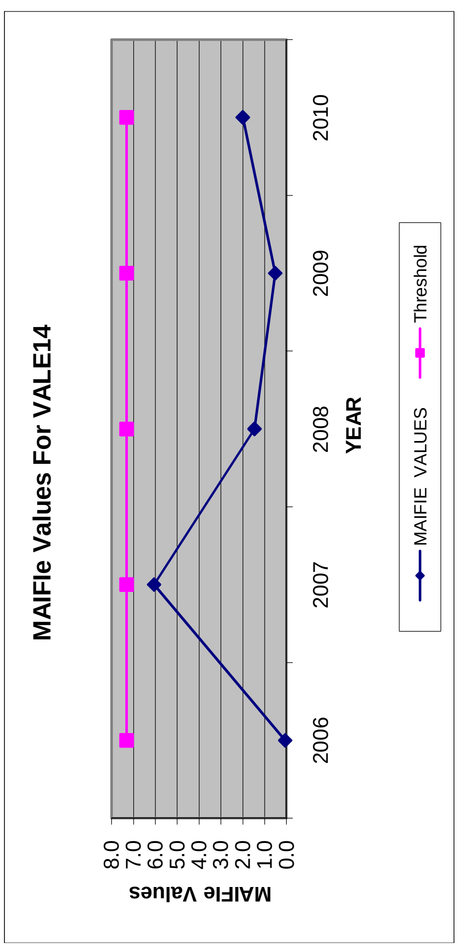

MAIFIe Values For RKVL11
MAIFIe Values
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

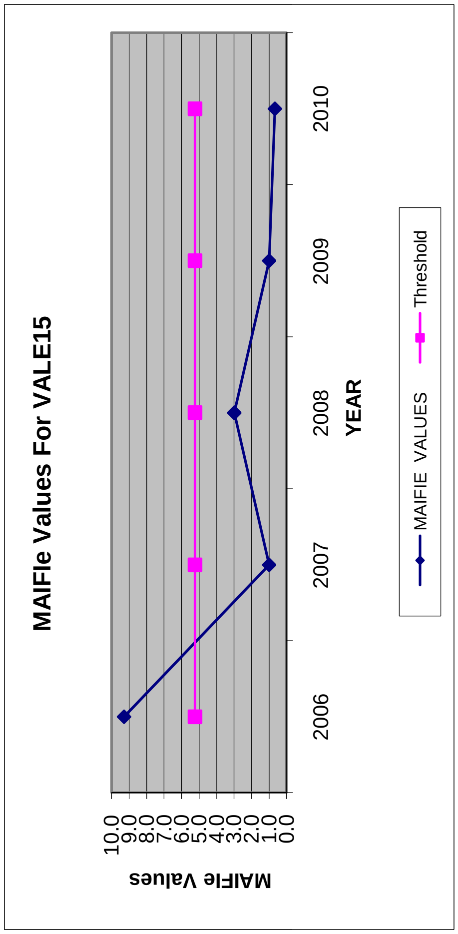

MAIFIe Values For UNTY11
MAIFIe Values
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

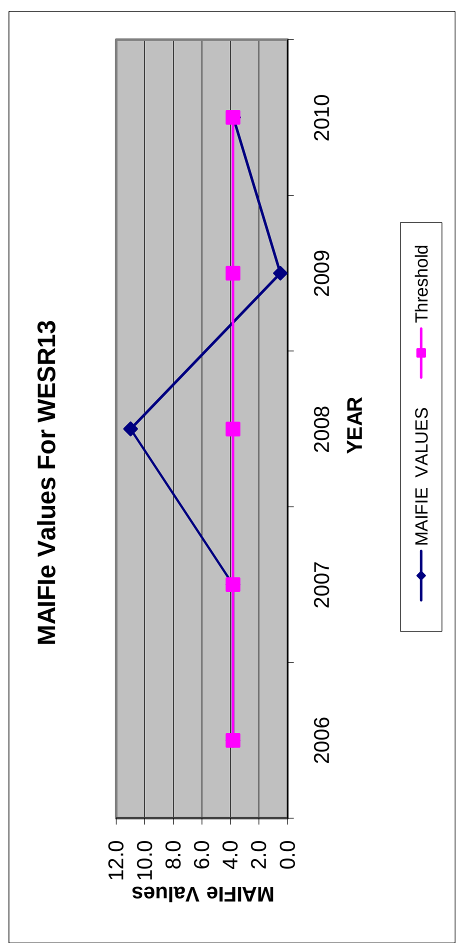

MAIFIe Values For UNTY12
MAIFIe Values
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

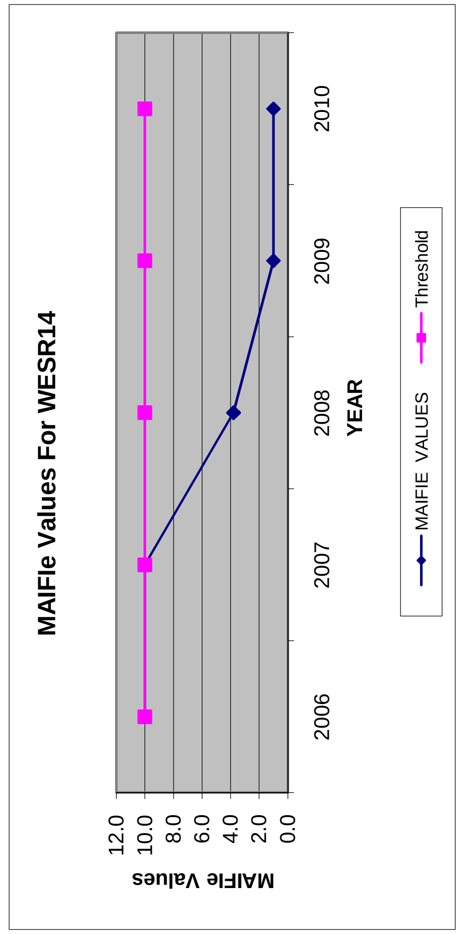

MAIFIe Values For VALE11
MAIFIe Values
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For VALE13
MAIFIe Values
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For VALE14
MAIFIe Values
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For VALE15
MAIFIe Values
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For WESR13
MAIFIe Values
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For WESR14
MAIFIe Values
12.0
10.0
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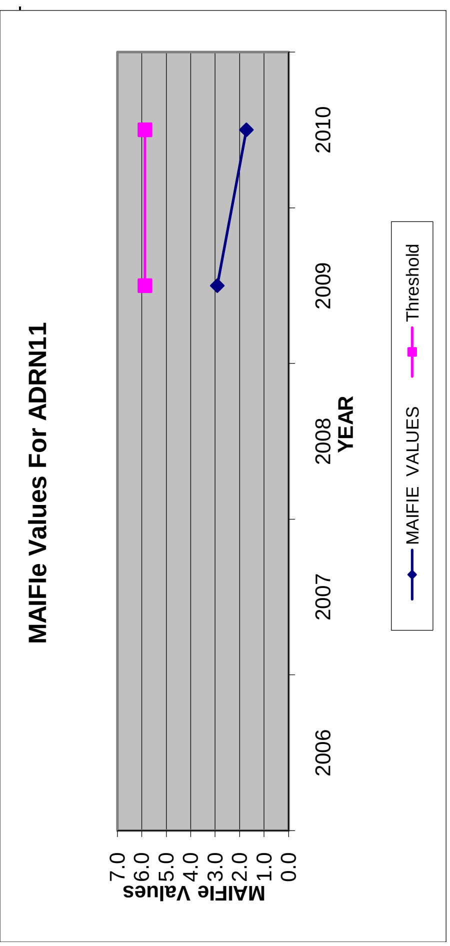
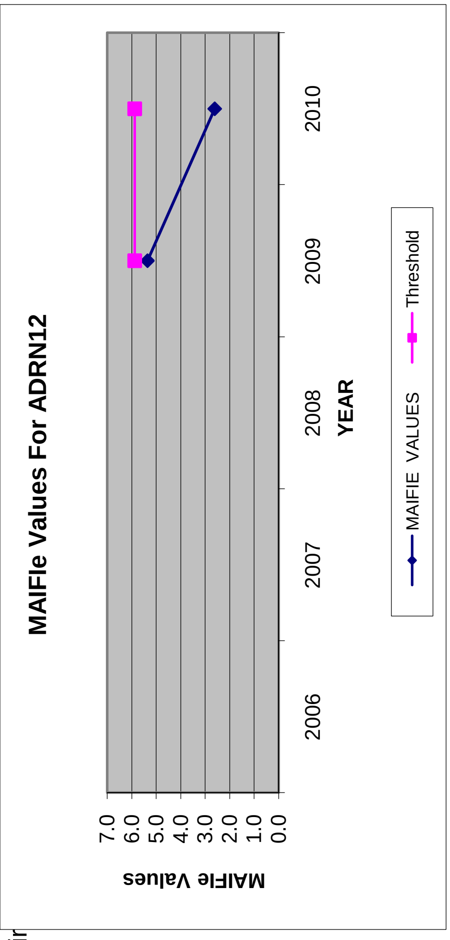
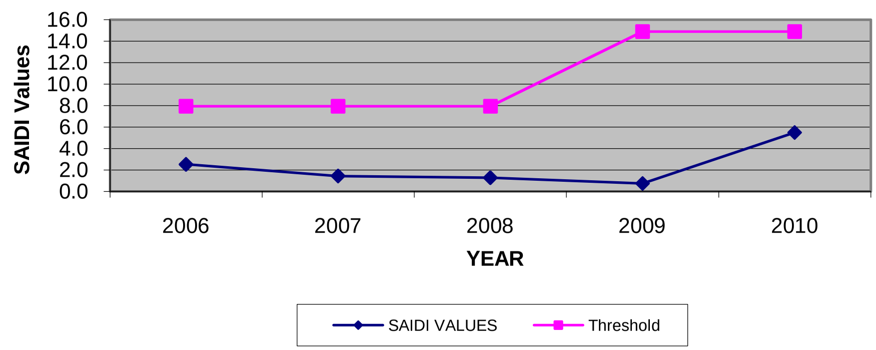
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

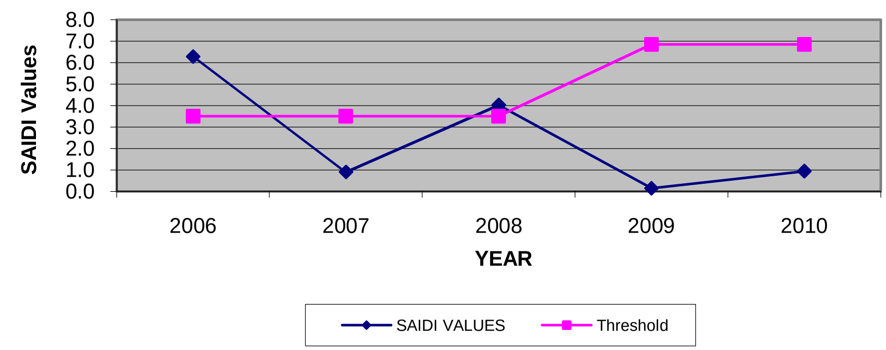

MAIFIe Values For ADRN11
MAIFIe Values
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold


MAIFIe Values For ADRN12
MAIFIe Values
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
MAIFIE VALUES
Threshold

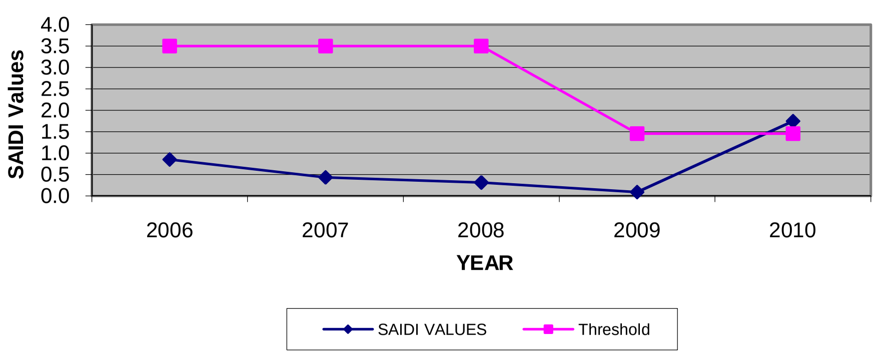
SAIDI Values For CARO11



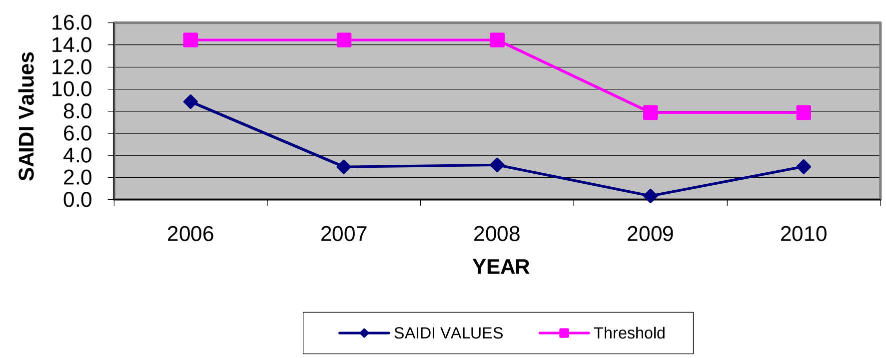
SAIDI Values For CARO12



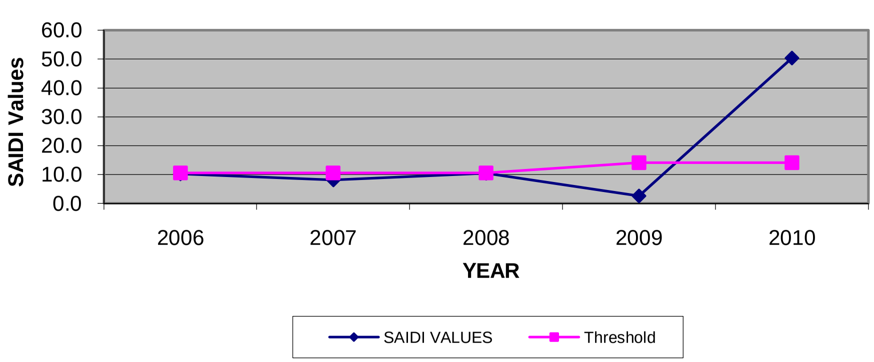
SAIDI Values For CARO13



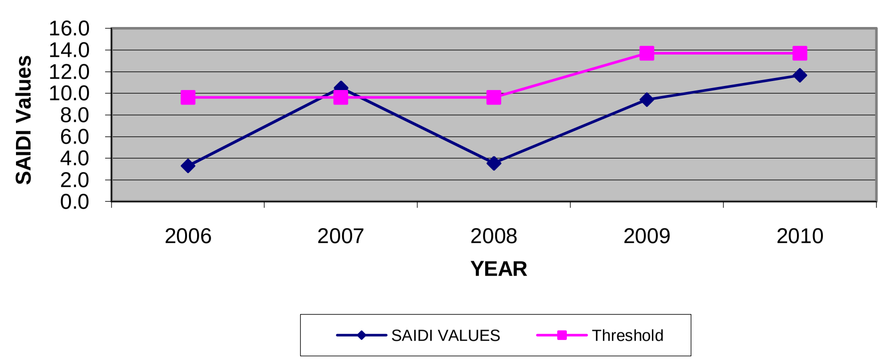
SAIDI Values For CWVY11

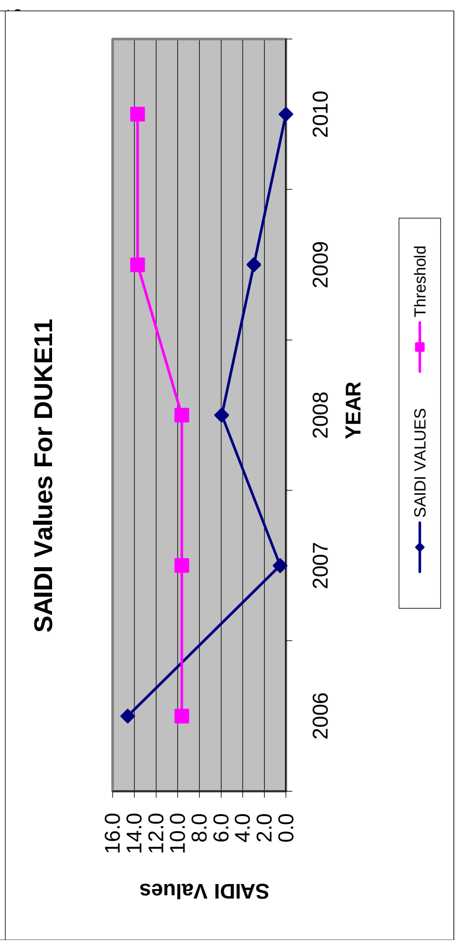


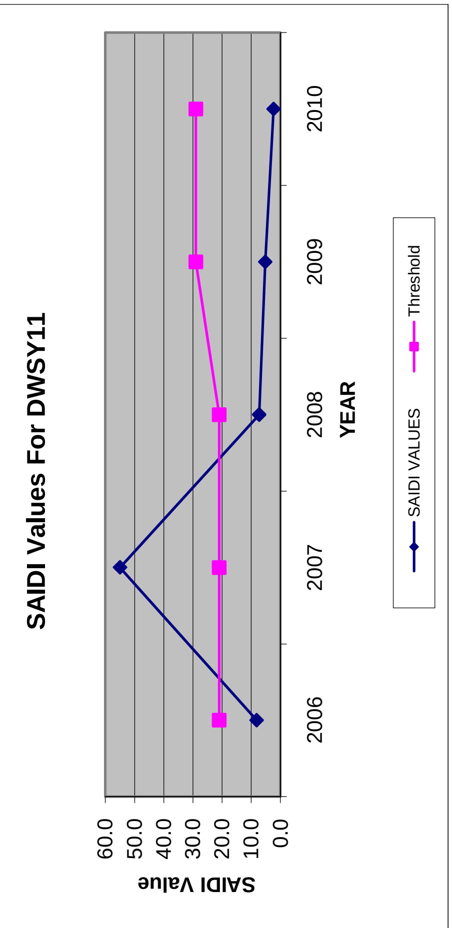
SAIDI Values For CWVY12

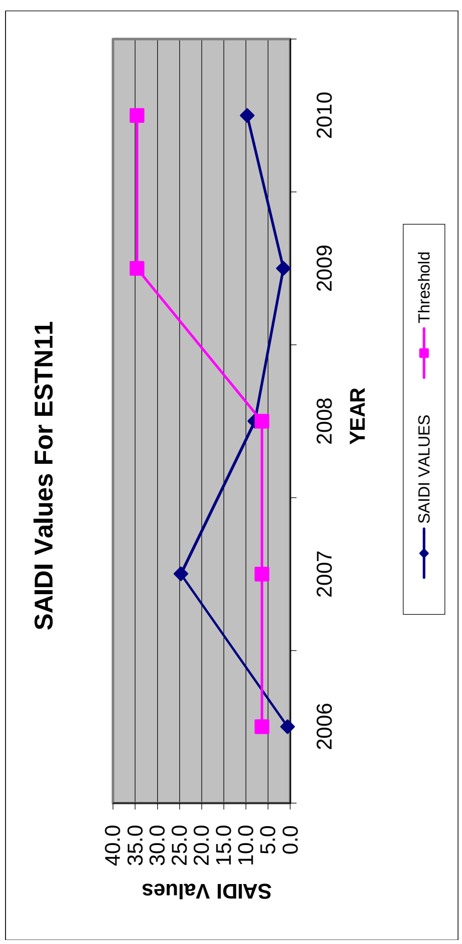


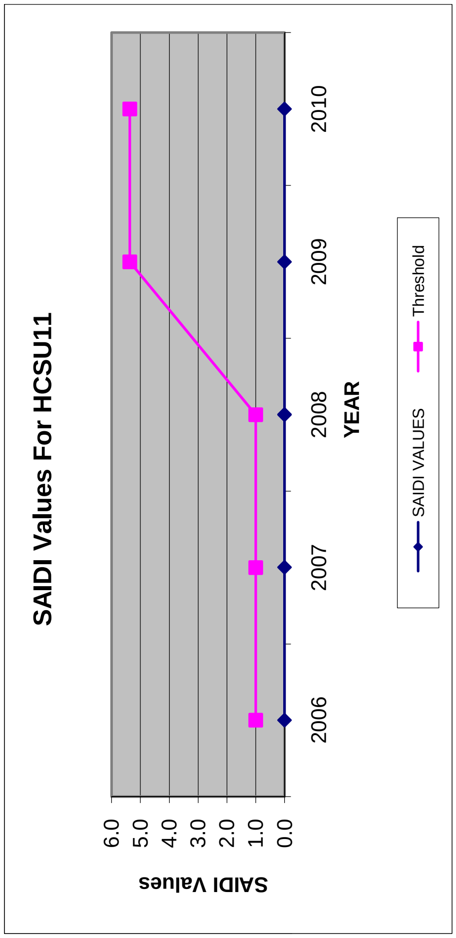
SAIDI Values For DRKE11

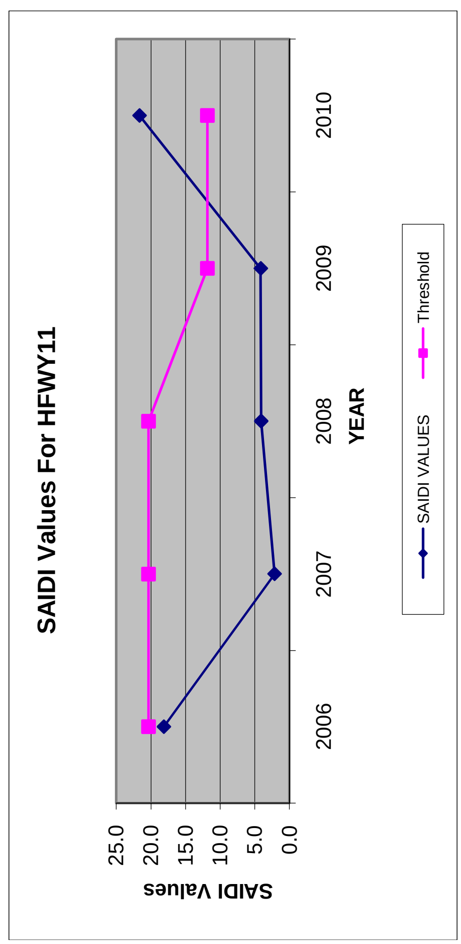



SAIDI Values For DUKE11
SAIDI Values
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For DWSY11
SAIDI Value
60.0
50.0
40.0
30.0
20.0
10.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ESTN11
SAIDI Values
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HCSU11
SAIDI Values
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HFWY11
SAIDI Values
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15.0
10.0
5.0
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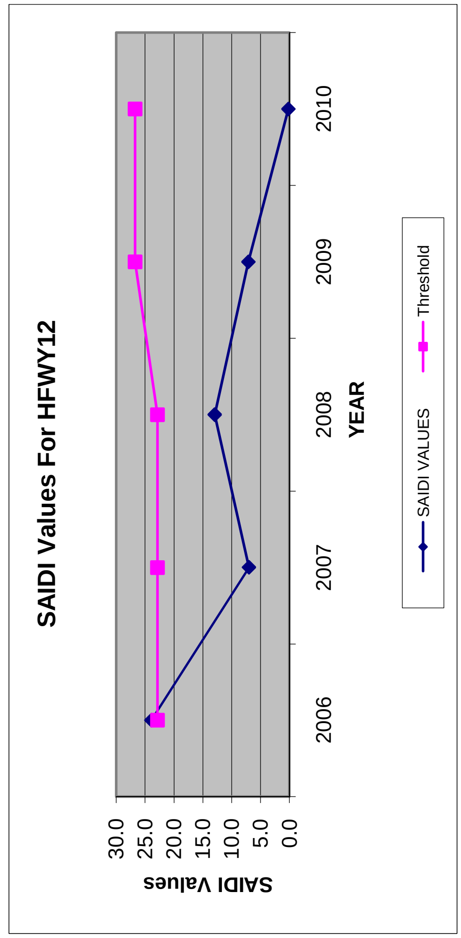
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HFWY12
SAIDI Values
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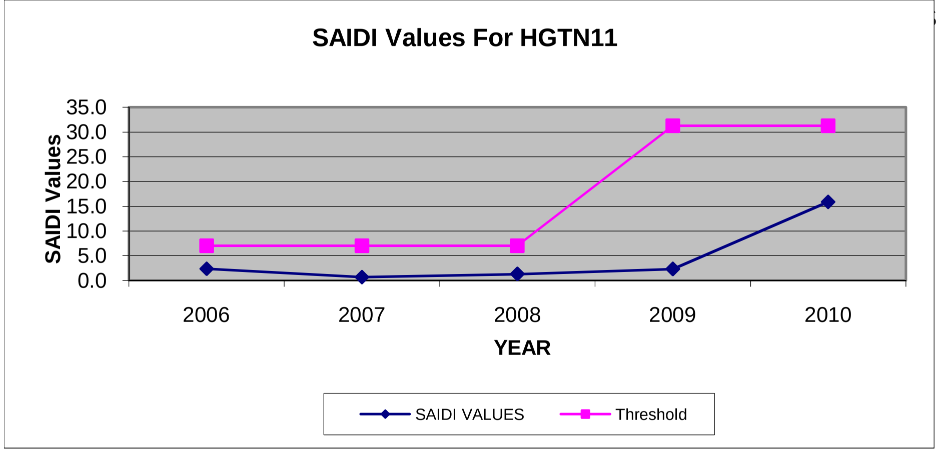
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HGTN11
SAIDI Values
35.0
30.0
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15.0
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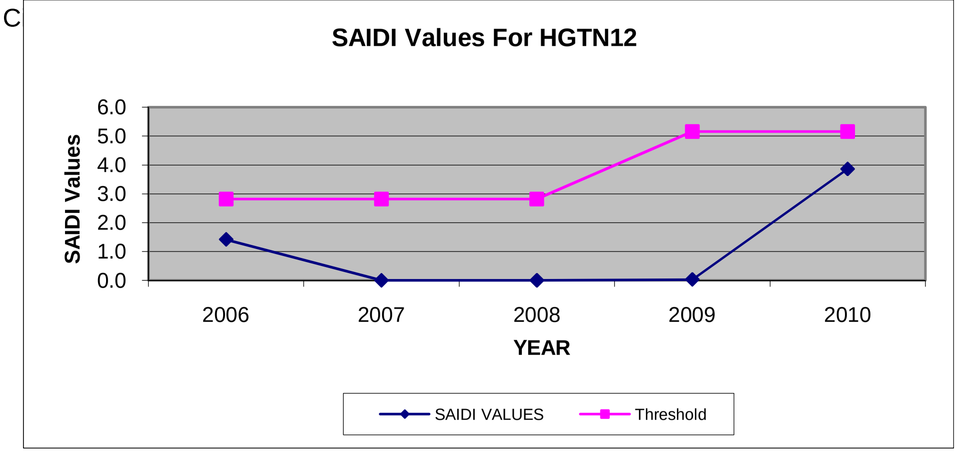
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HGTN12
SAIDI Values
6.0
5.0
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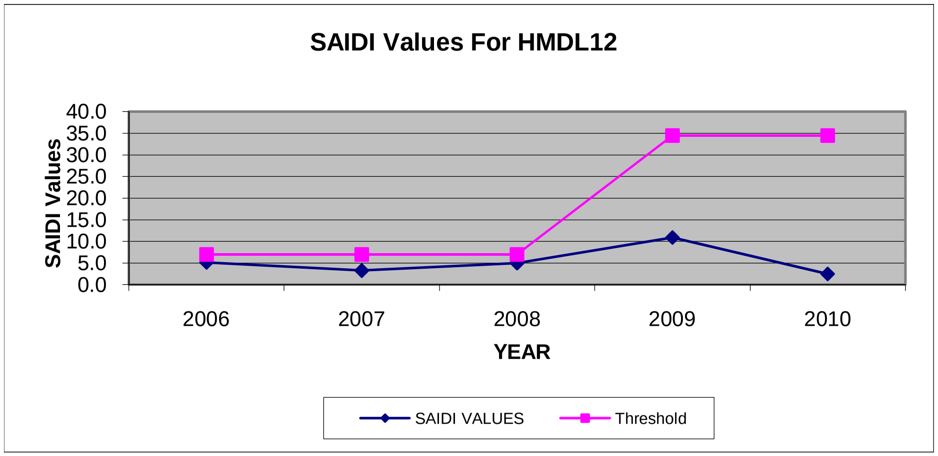
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HMDL12
SAIDI Values
40.0
35.0
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5.0
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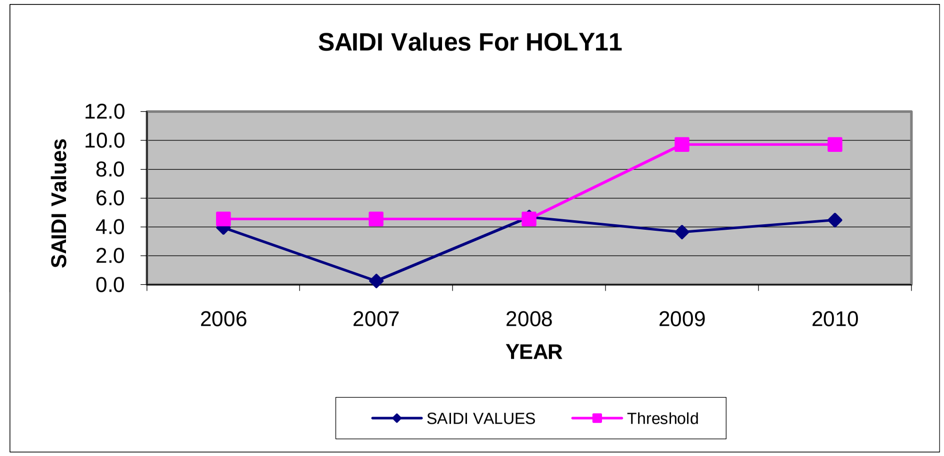
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HOLY11
SAIDI Values
12.0
10.0
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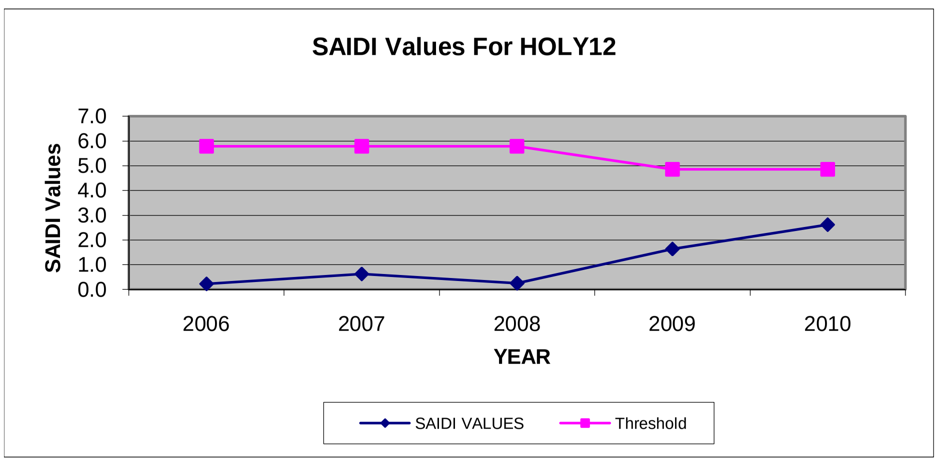
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HOLY12
SAIDI Values
7.0
6.0
5.0
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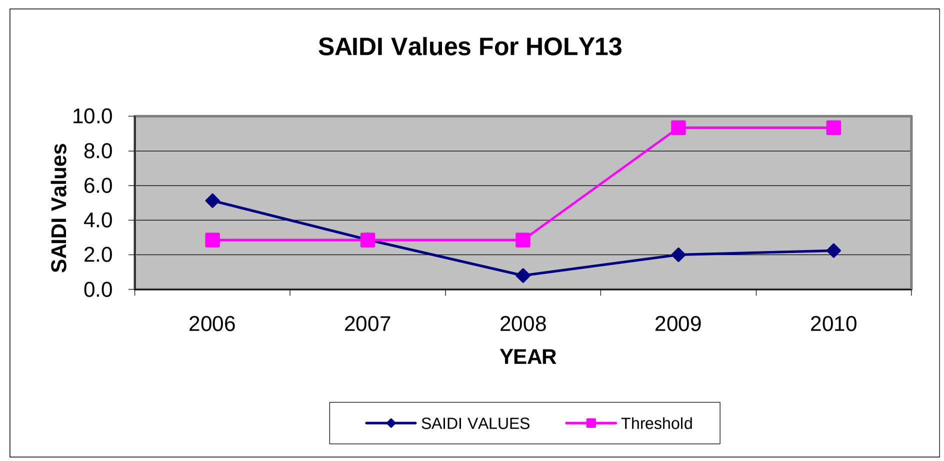
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HOLY13
SAIDI Values
10.0
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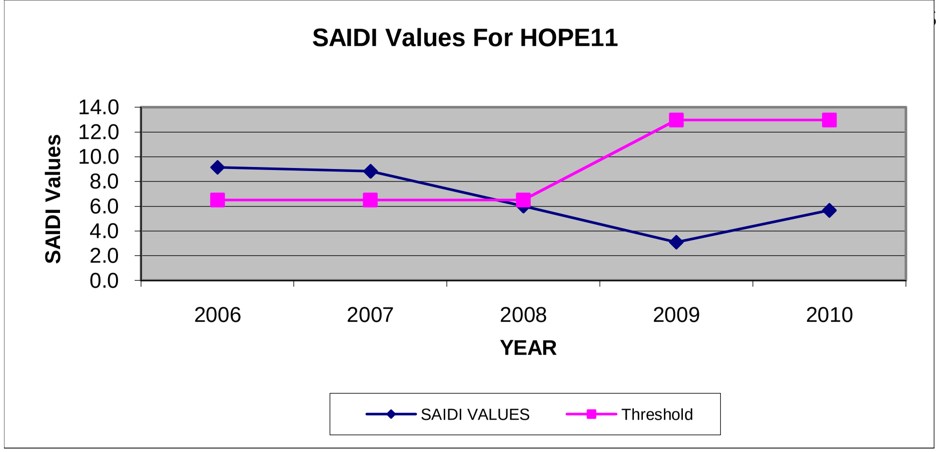
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HOPE11
SAIDI Values
14.0
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6.0
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2.0
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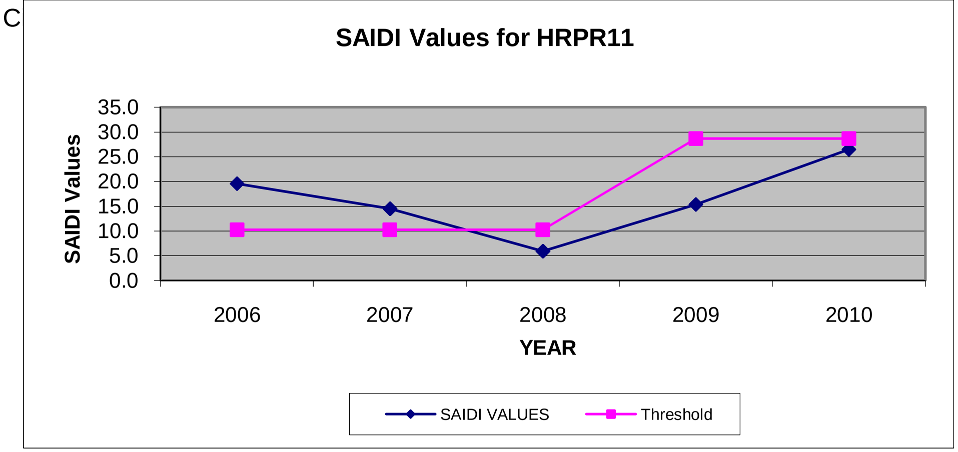
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values for HRPR11
SAIDI Values
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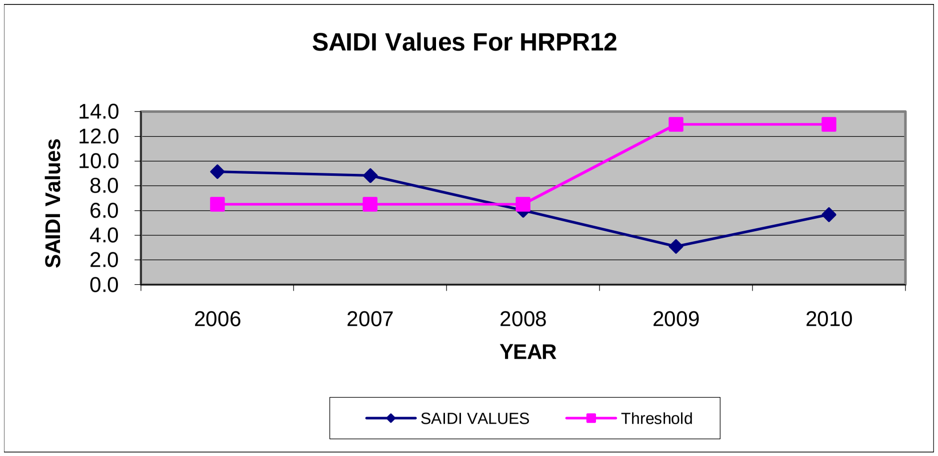
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For HRPR12
SAIDI Values
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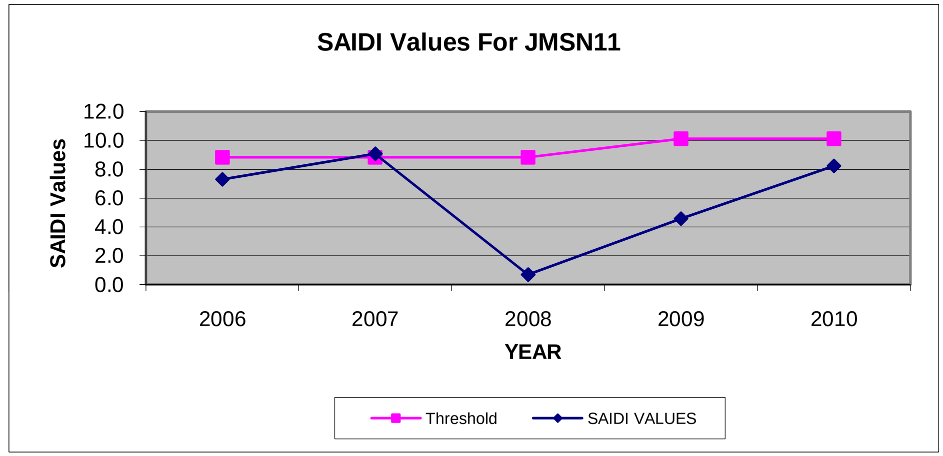
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For JMSN11
SAIDI Values
12.0
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6.0
4.0
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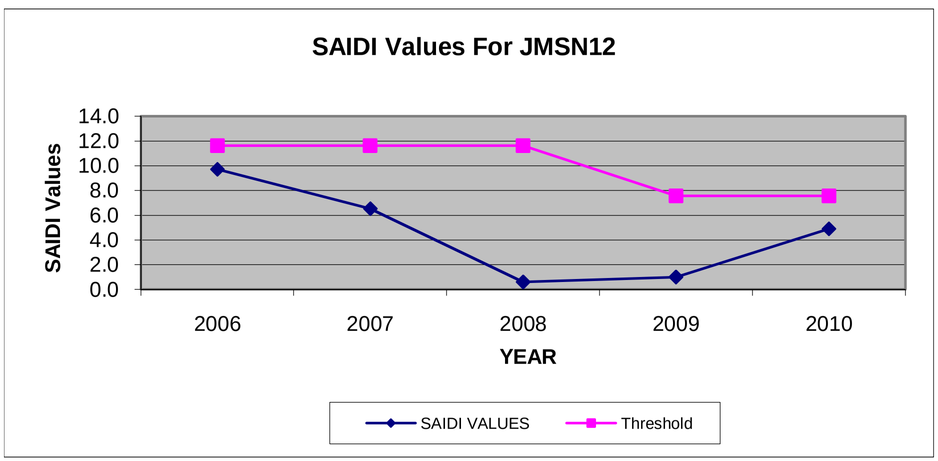
2006
2007
2008
2009
2010
YEAR
Threshold
SAIDI VALUES


SAIDI Values For JMSN12
SAIDI Values
14.0
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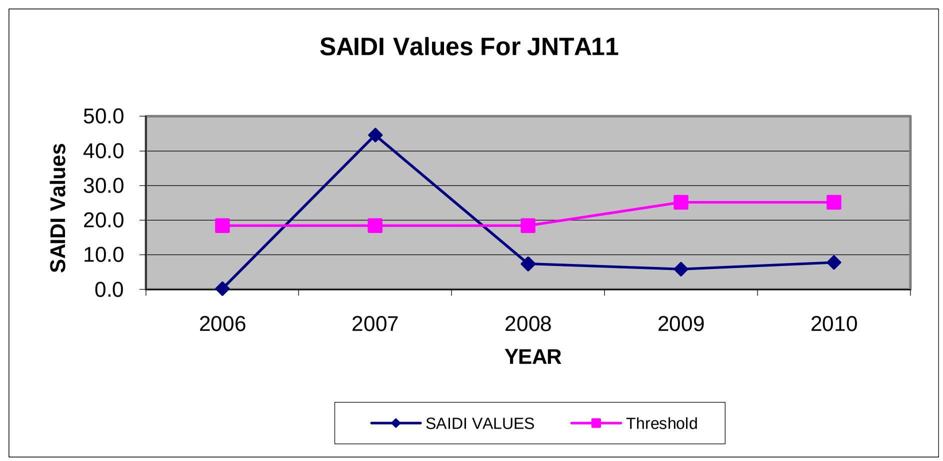
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For JNTA11
SAIDI Values
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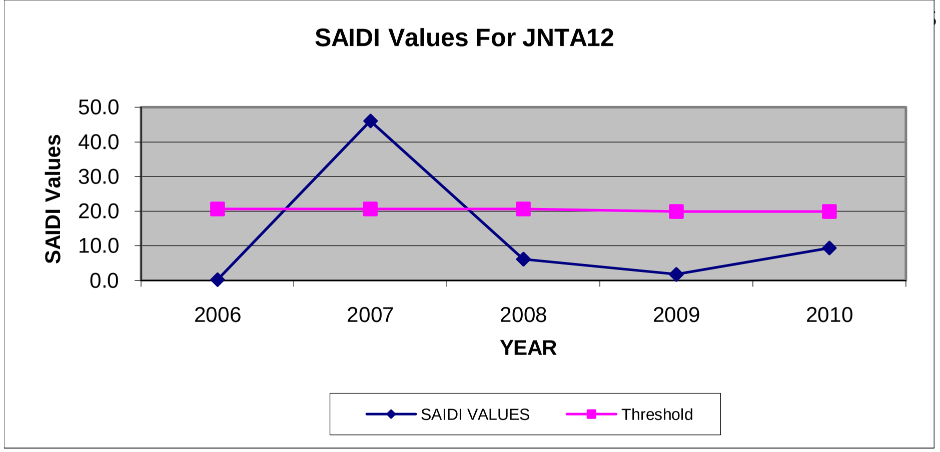
30.0
20.0
10.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For JNTA12
SAIDI Values
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30.0
20.0
10.0
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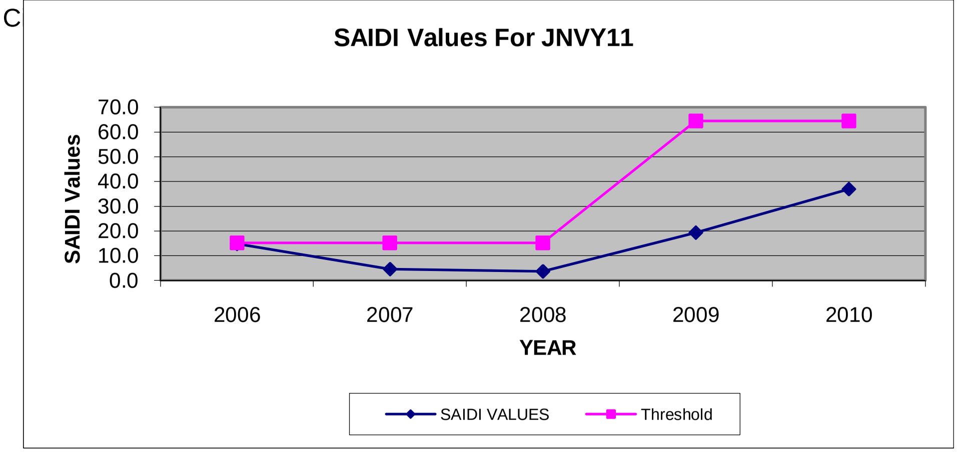
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For JNVY11
SAIDI Values
70.0
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30.0
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10.0
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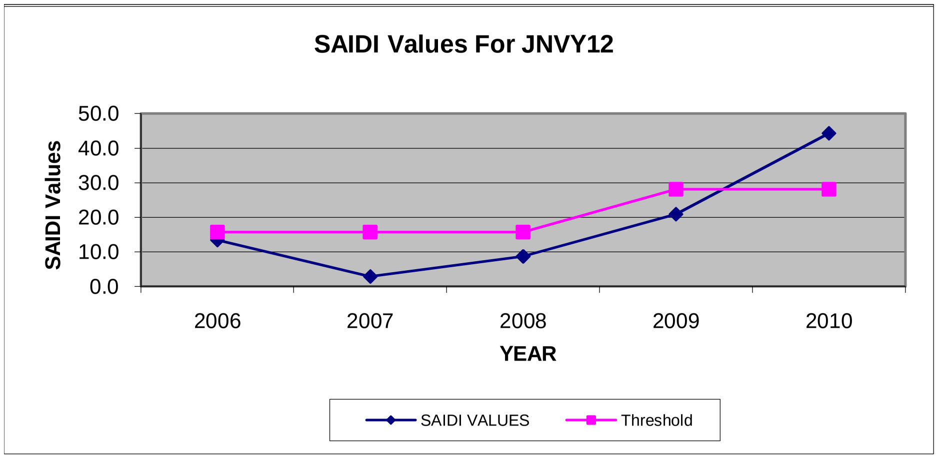
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For JNVY12
SAIDI Values
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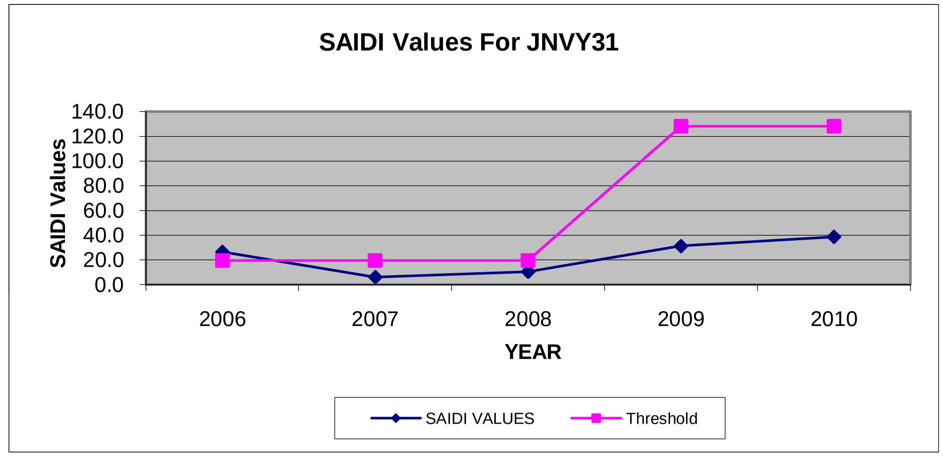
40.0
30.0
20.0
10.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For JNVY31
SAIDI Values
140.0
120.0
100.0
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60.0
40.0
20.0
0.0
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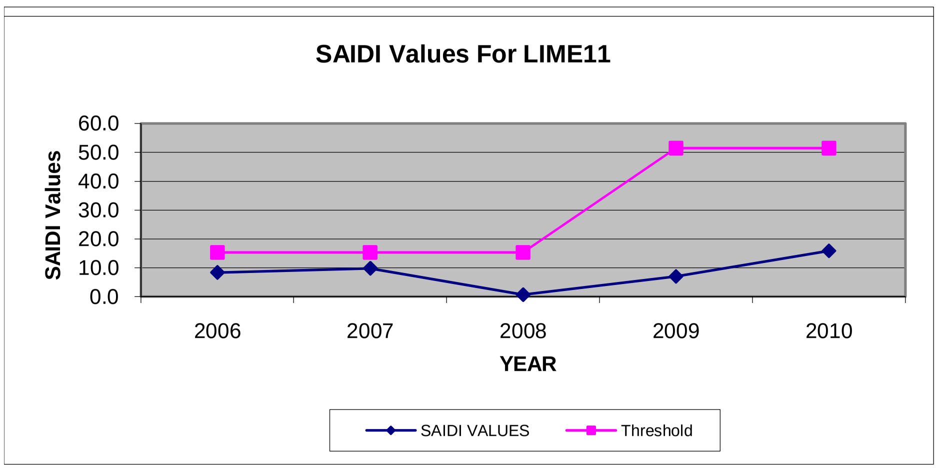
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For LIME11
SAIDI Values
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30.0
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10.0
0.0
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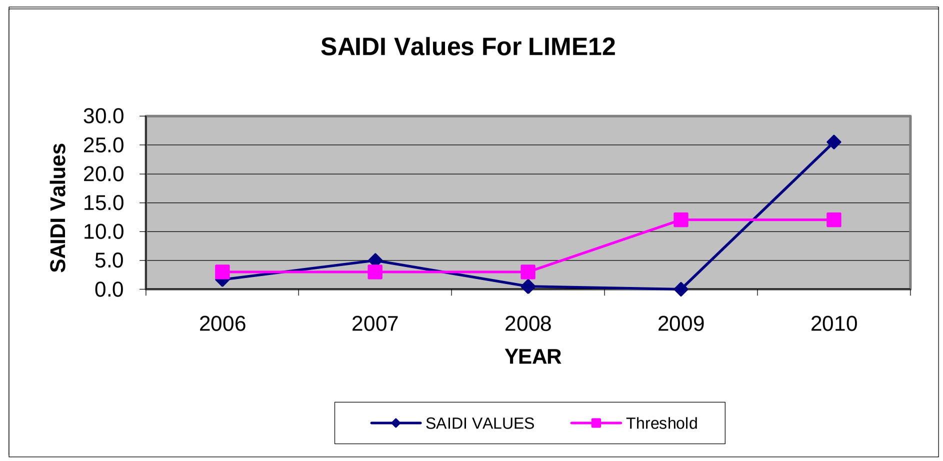
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For LIME12
SAIDI Values
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15.0
10.0
5.0
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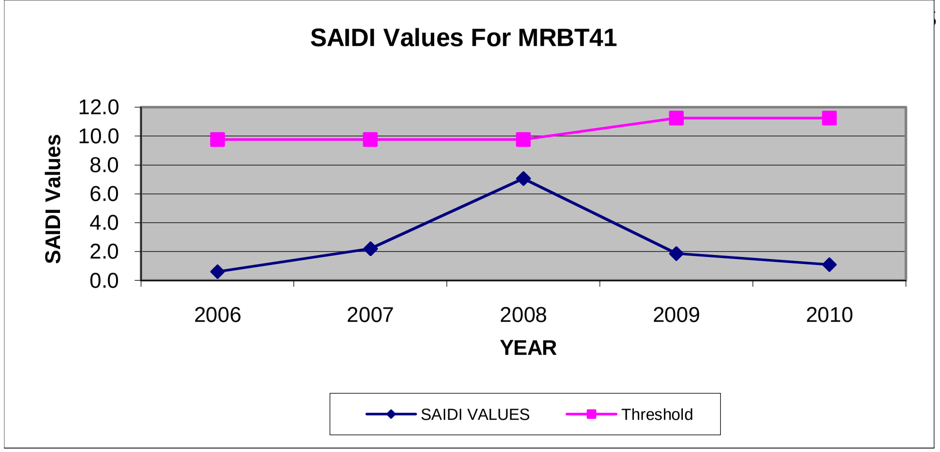
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For MRBT41
SAIDI Values
12.0
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6.0
4.0
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0.0
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2007
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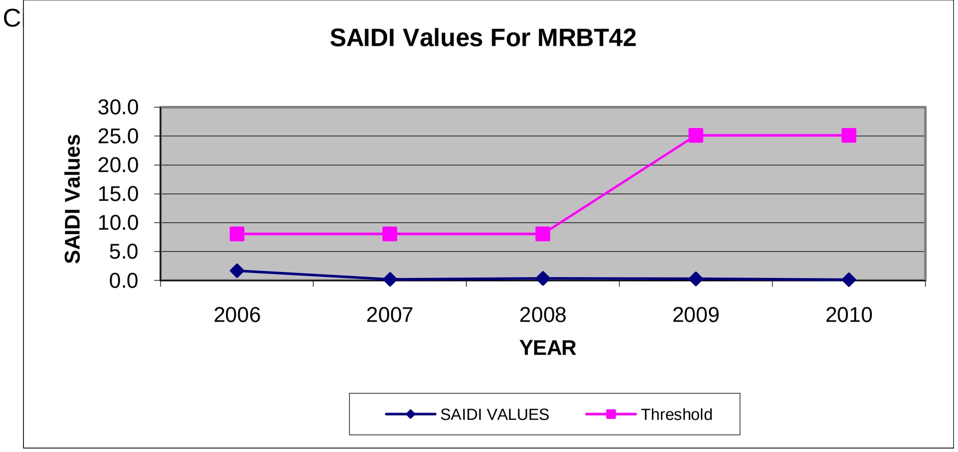
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For MRBT42
SAIDI Values
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25.0
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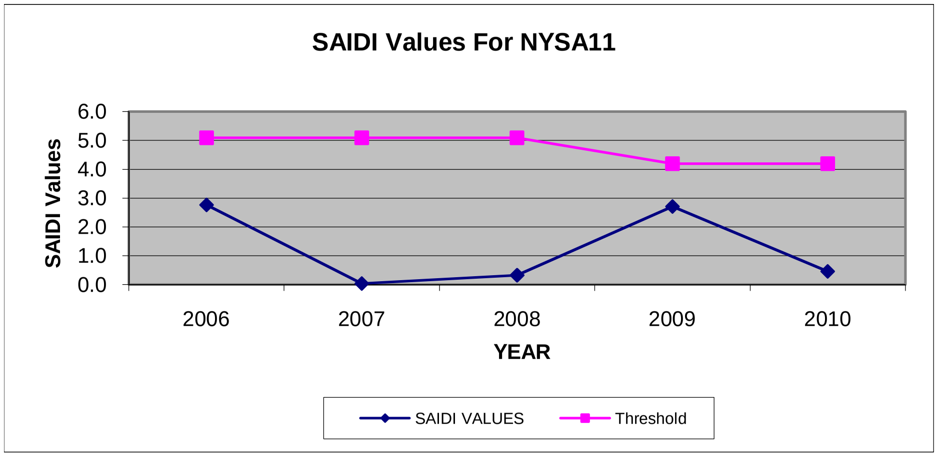
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For NYSA11
SAIDI Values
6.0
5.0
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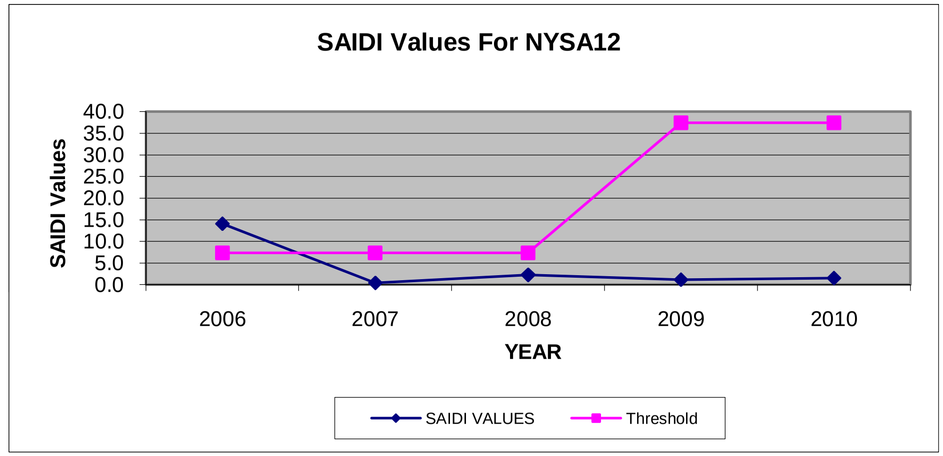
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For NYSA12
SAIDI Values
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35.0
30.0
25.0
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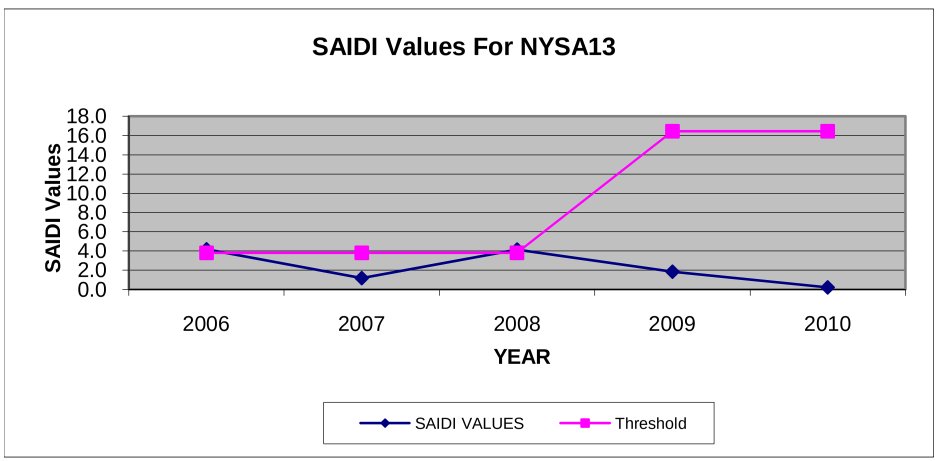
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For NYSA13
SAIDI Values
18.0
16.0
14.0
12.0
10.0
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6.0
4.0
2.0
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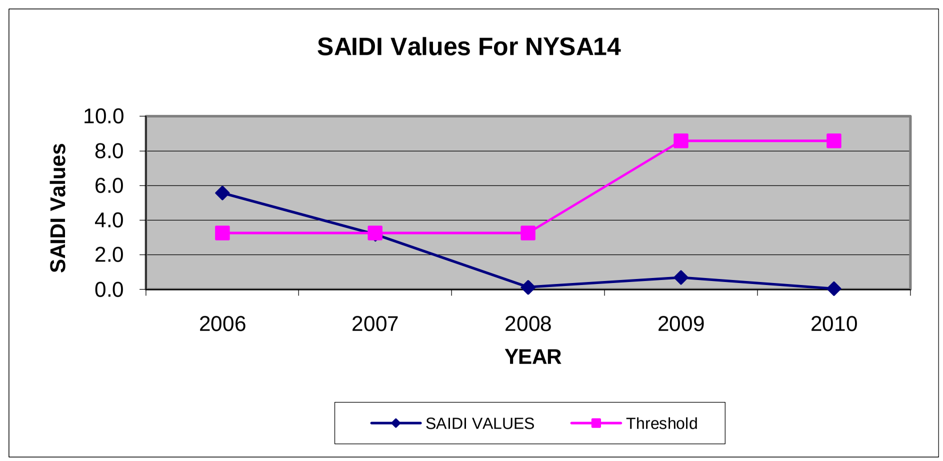
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For NYSA14
SAIDI Values
10.0
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6.0
4.0
2.0
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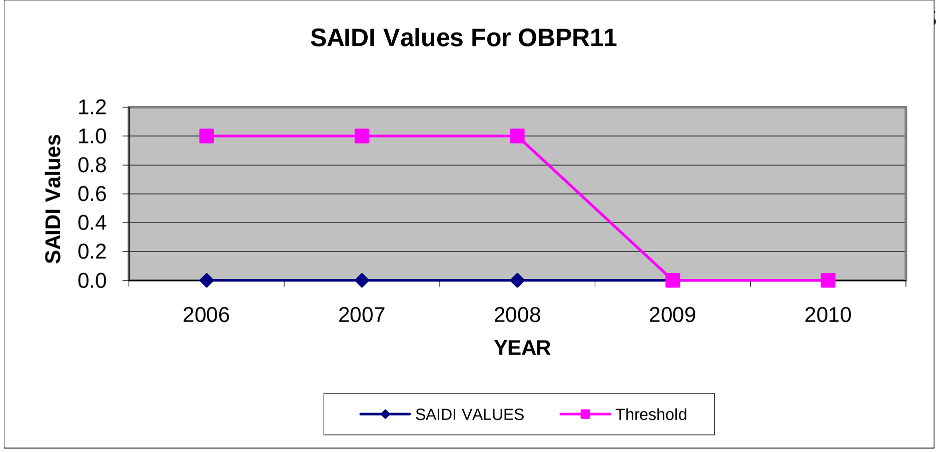
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For OBPR11
SAIDI Values
1.2
1.0
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0.6
0.4
0.2
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2006
2007
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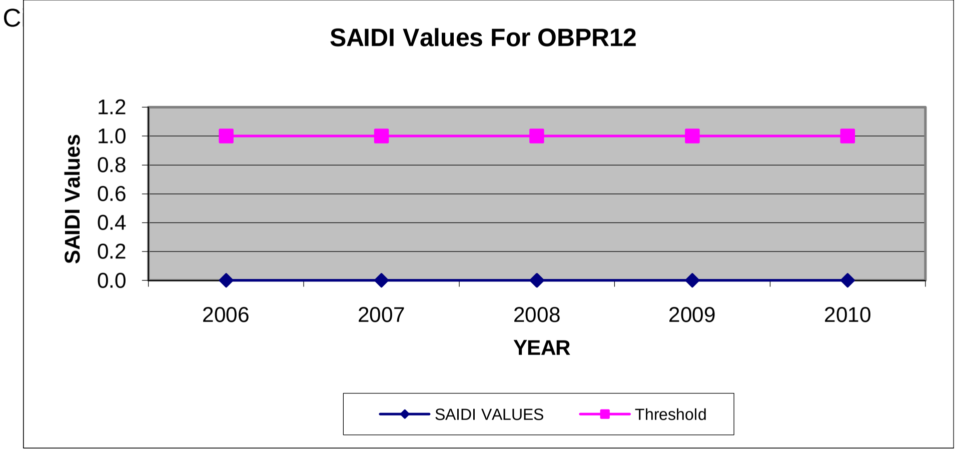
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For OBPR12
SAIDI Values
1.2
1.0
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0.6
0.4
0.2
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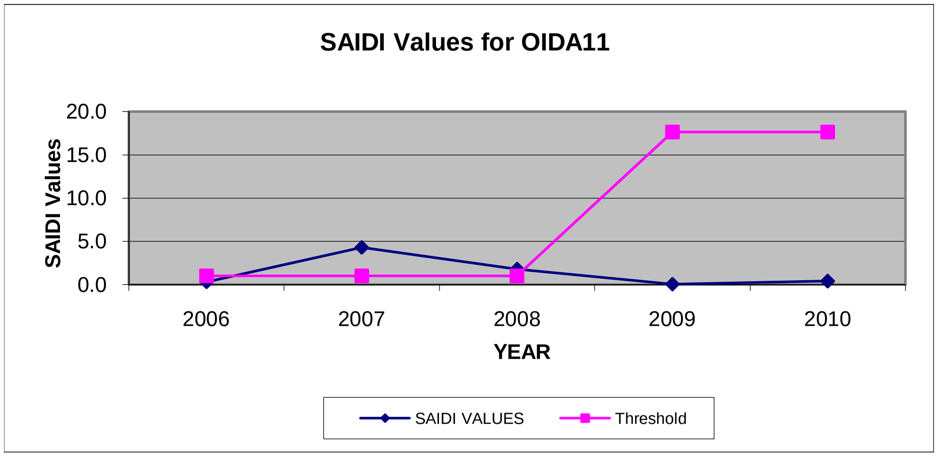
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values for OIDA11
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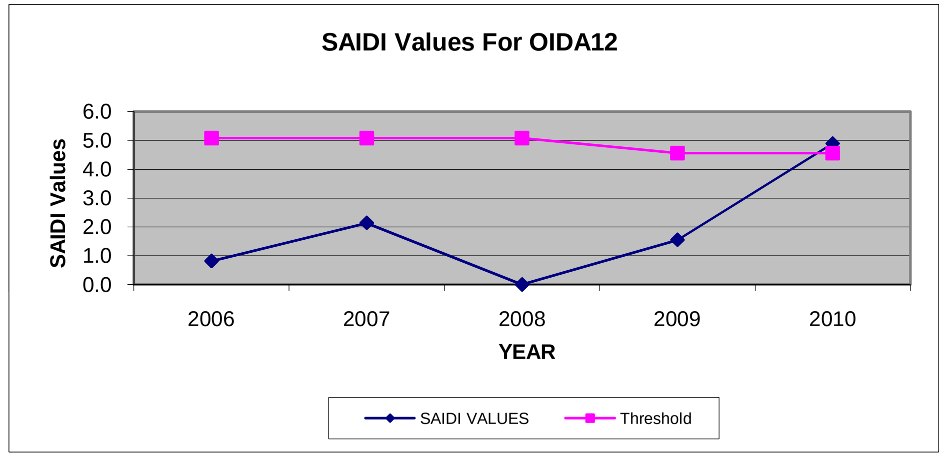
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For OIDA12
SAIDI Values
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3.0
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2007
2008
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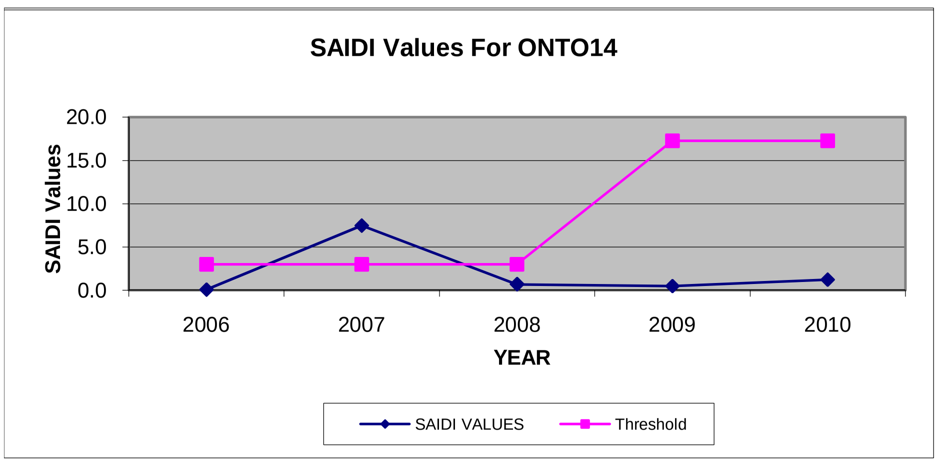
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ONTO14
SAIDI Values
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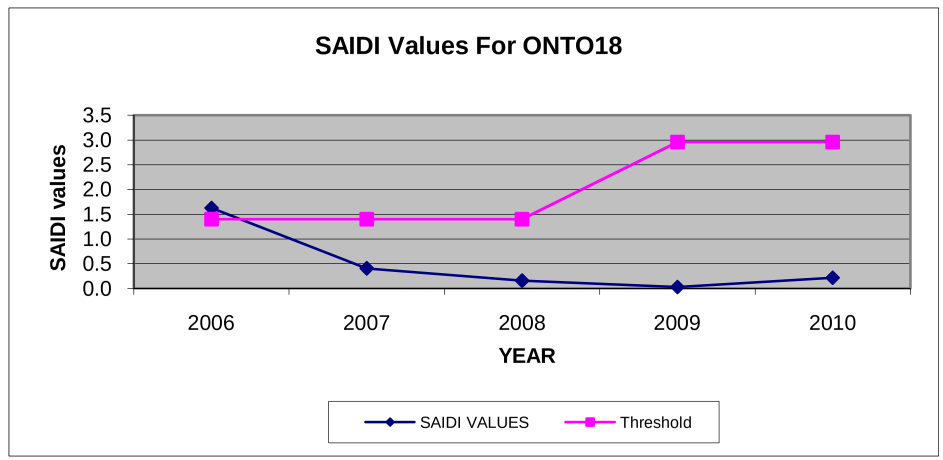
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ONTO18
SAIDI values
3.5
3.0
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2.0
1.5
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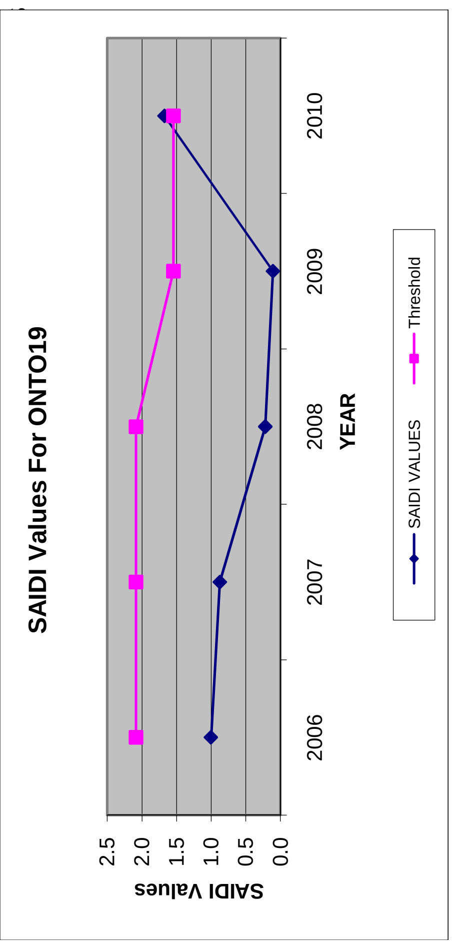
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ONTO19
SAIDI Values
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1.0
0.5
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2007
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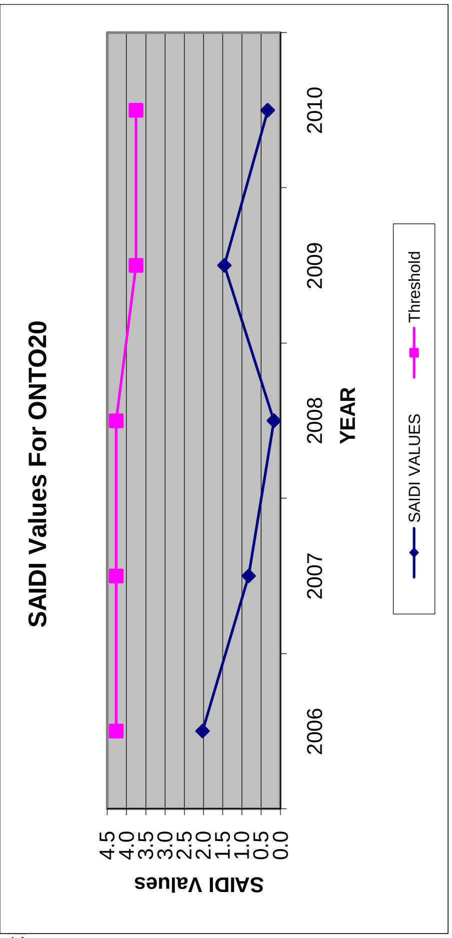
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ONTO20
SAIDI Values
4.5
4.0
3.5
3.0
2.5
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1.5
1.0
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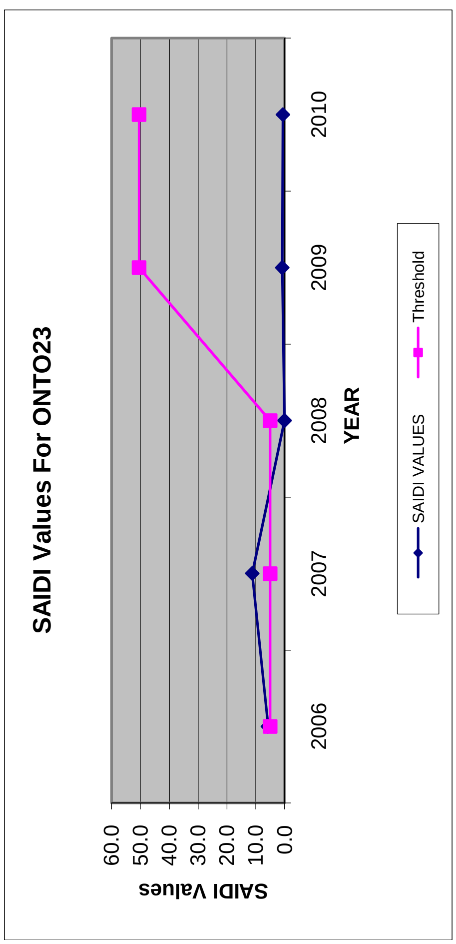
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ONTO23
SAIDI Values
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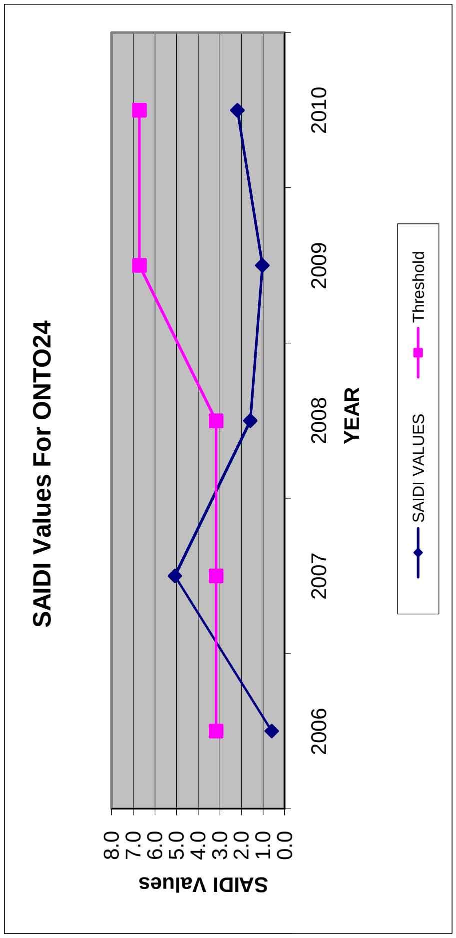
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ONTO24
SAIDI Values
8.0
7.0
6.0
5.0
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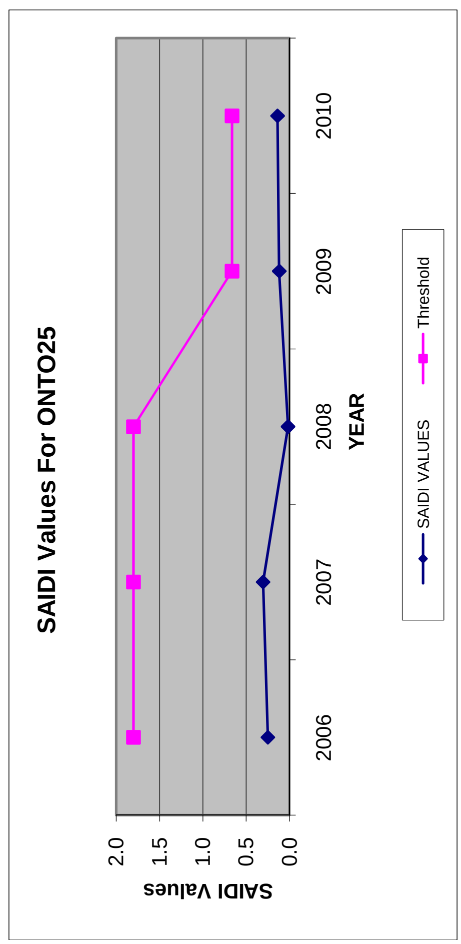
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For ONTO25
SAIDI Values
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1.0
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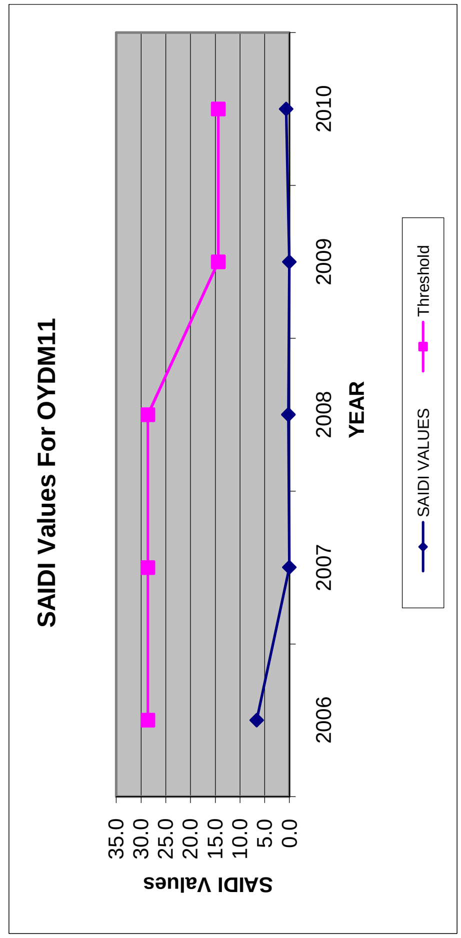
YEAR
SAIDI VALUES
Threshold


SAIDI Values For OYDM11
SAIDI Values
35.0
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2006
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2008
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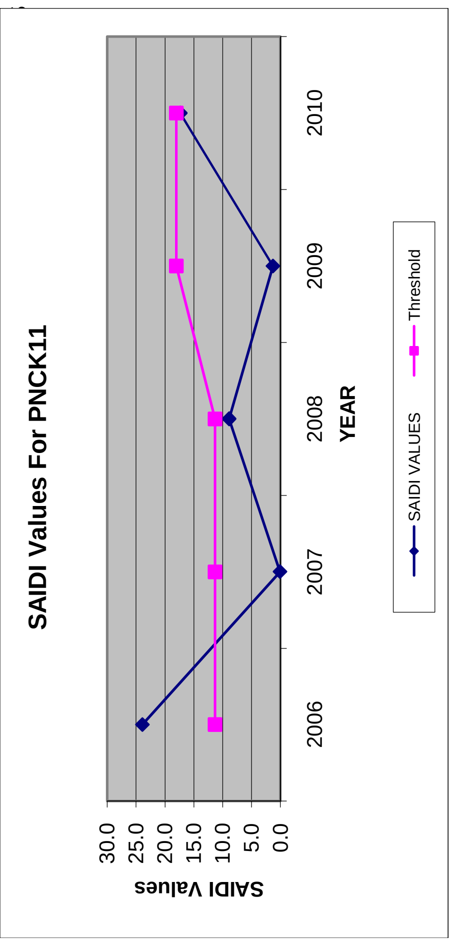
2010
YEAR
SAIDI VALUES
Threshold

- C


SAIDI Values For PNCK11
SAIDI Values
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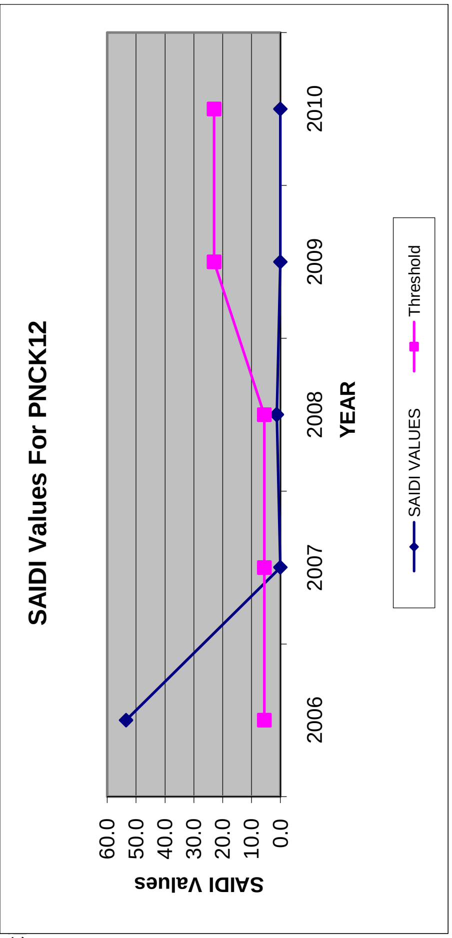
2010
YEAR
SAIDI VALUES
Threshold


SAIDI Values For PNCK12
SAIDI Values
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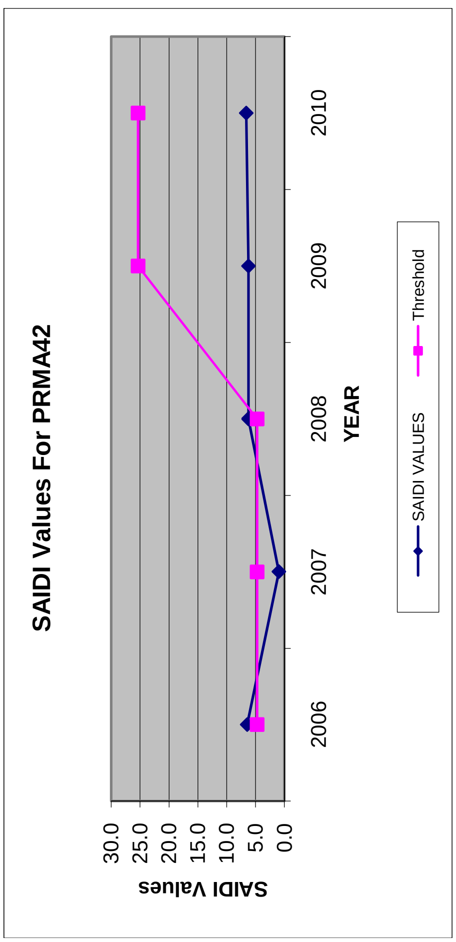
YEAR
SAIDI VALUES
Threshold


SAIDI Values For PRMA42
SAIDI Values
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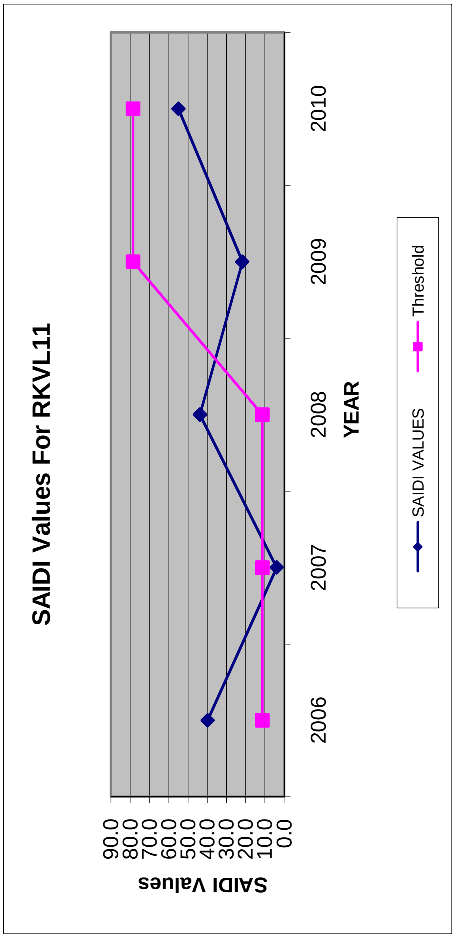
YEAR
SAIDI VALUES
Threshold


SAIDI Values For RKVL11
SAIDI Values
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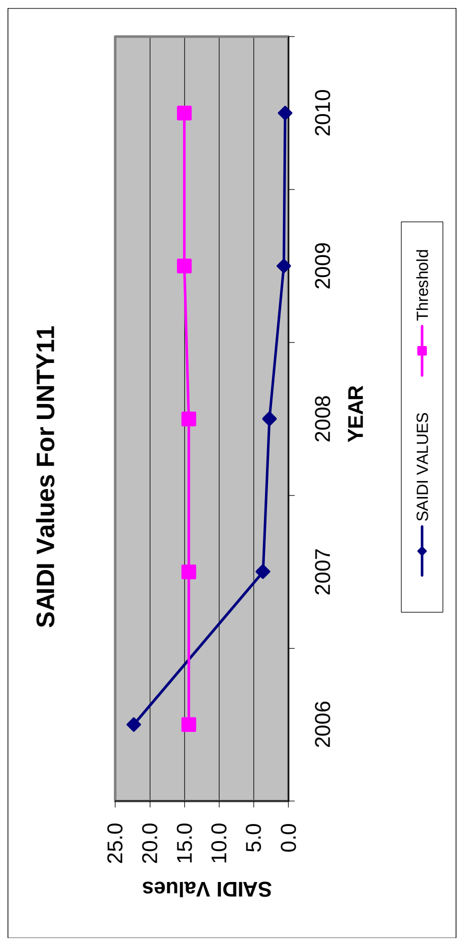
YEAR
SAIDI VALUES
Threshold


SAIDI Values For UNTY11
SAIDI Values
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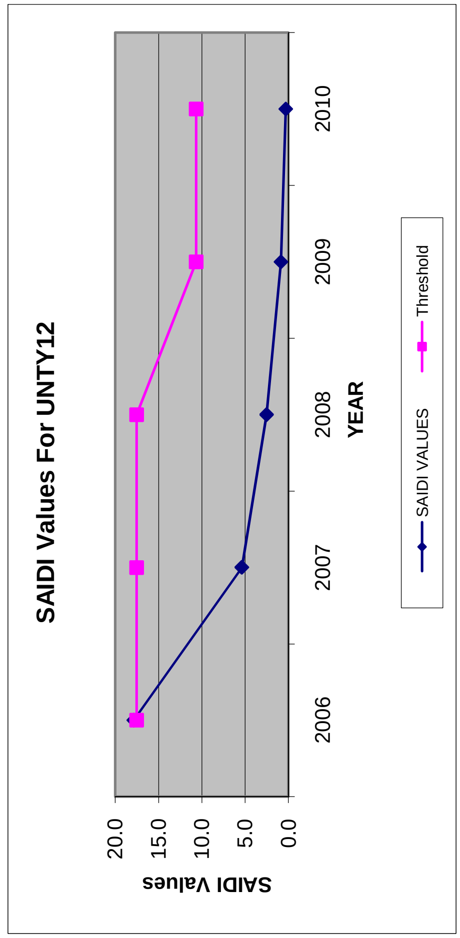
YEAR
SAIDI VALUES
Threshold


SAIDI Values For UNTY12
SAIDI Values
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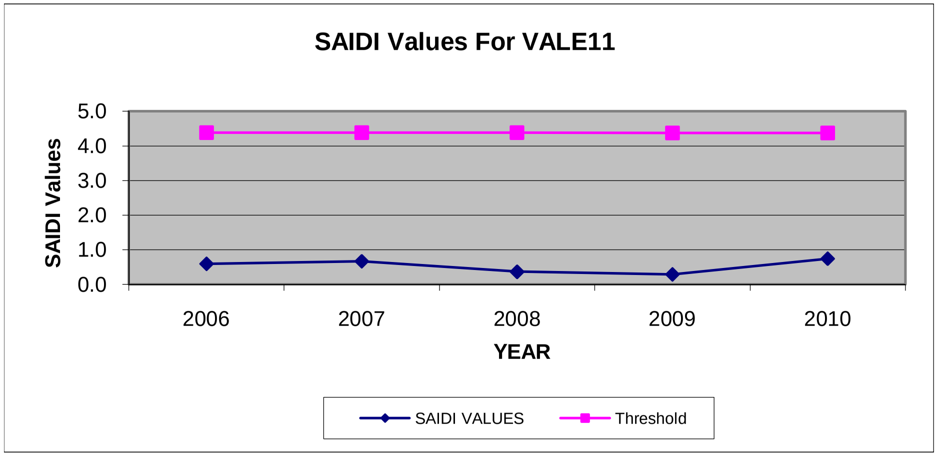
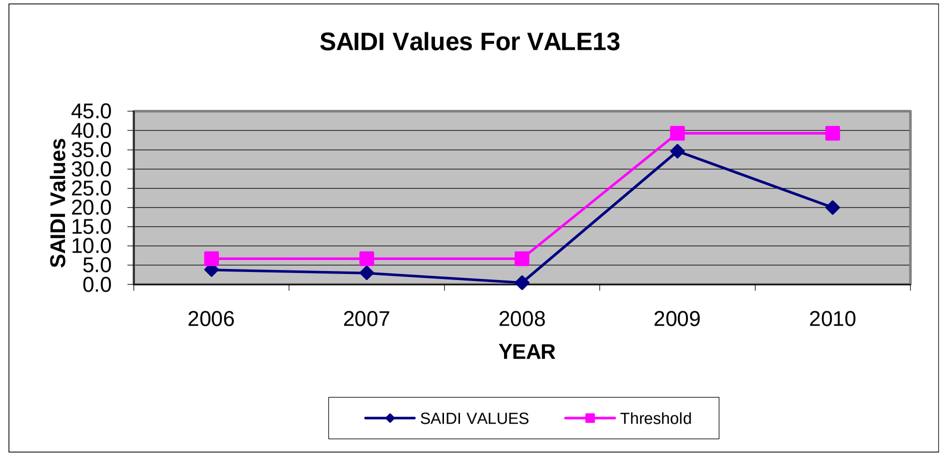
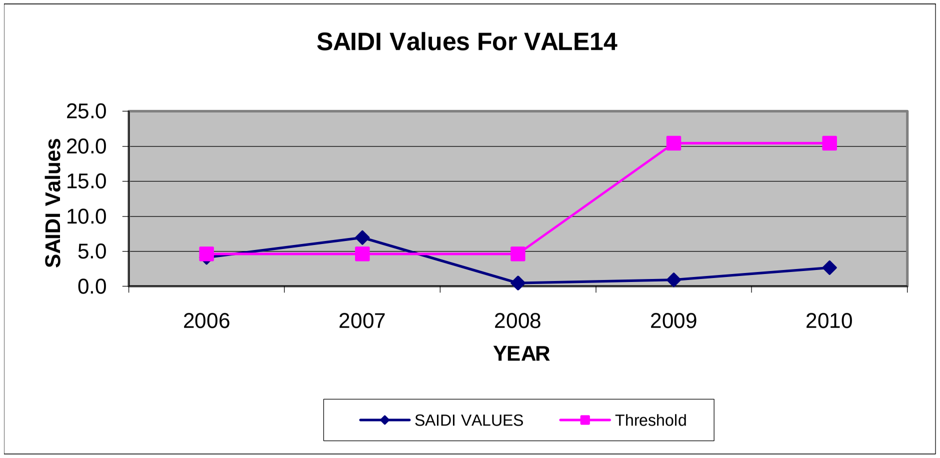
2006
2007
2008
2009
2010
YEAR
SAIDI VALUES
Threshold

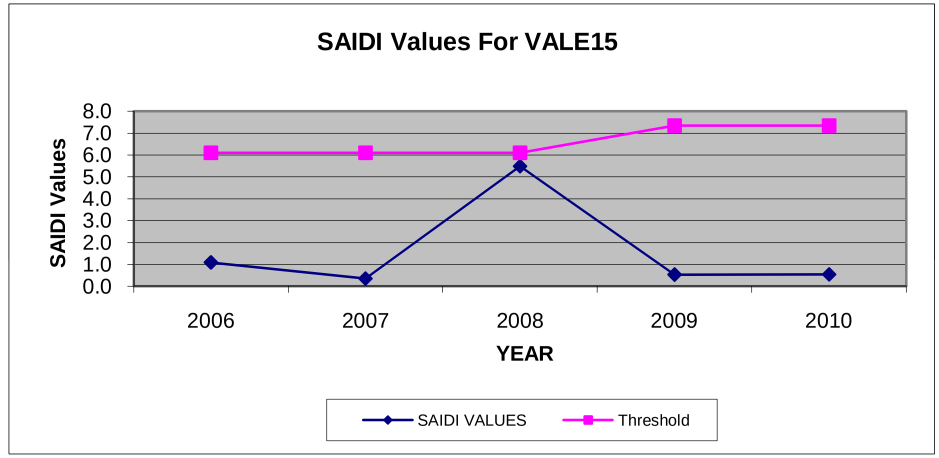
- C

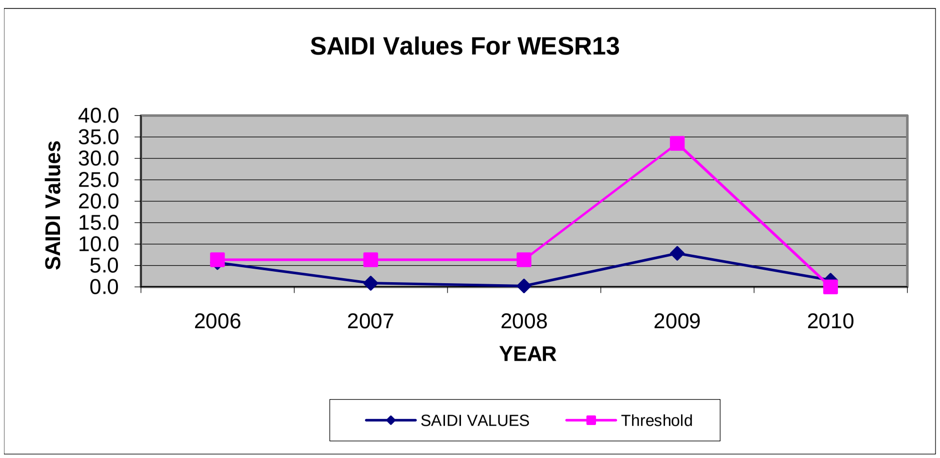
CHARTS - Circuit SAIDI Values

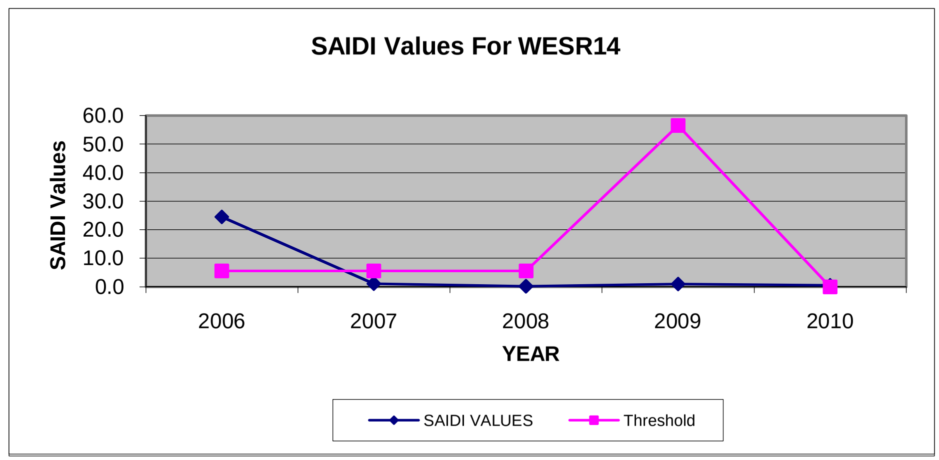




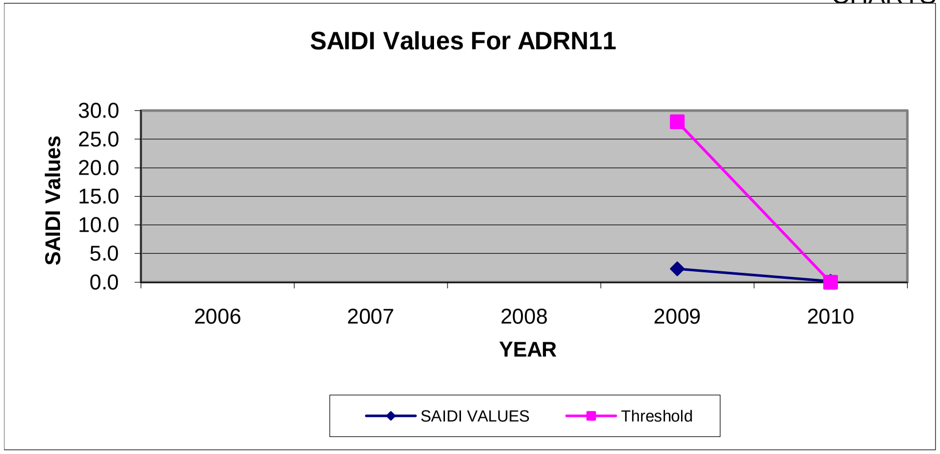


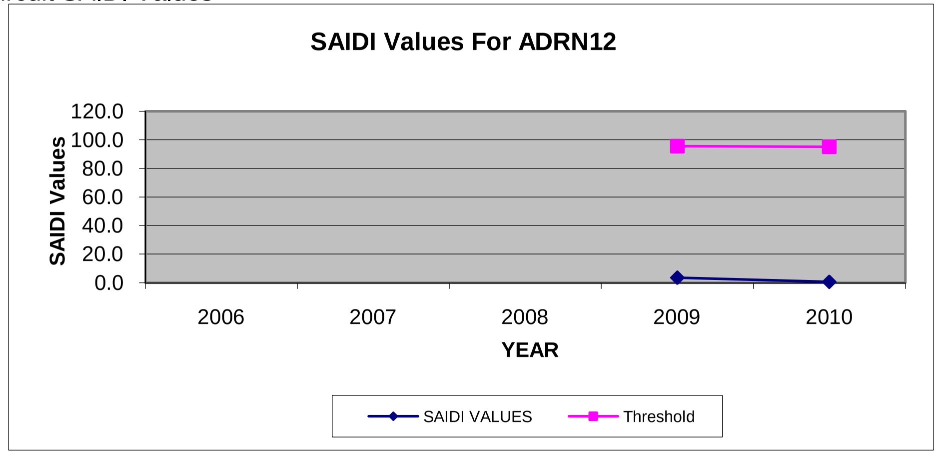




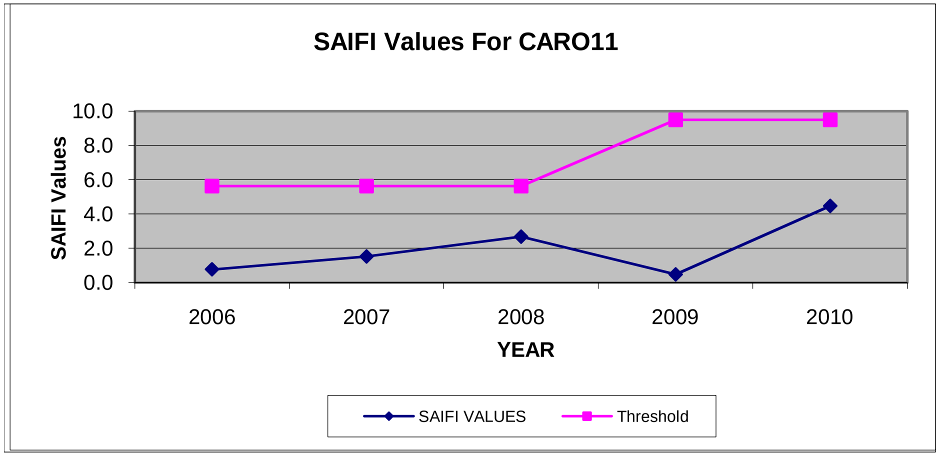


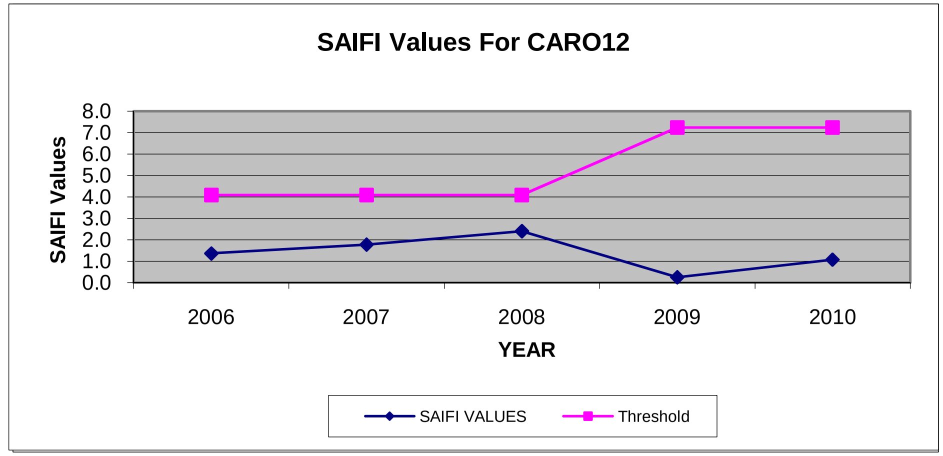
CHARTS - Circuit SAIDI Values

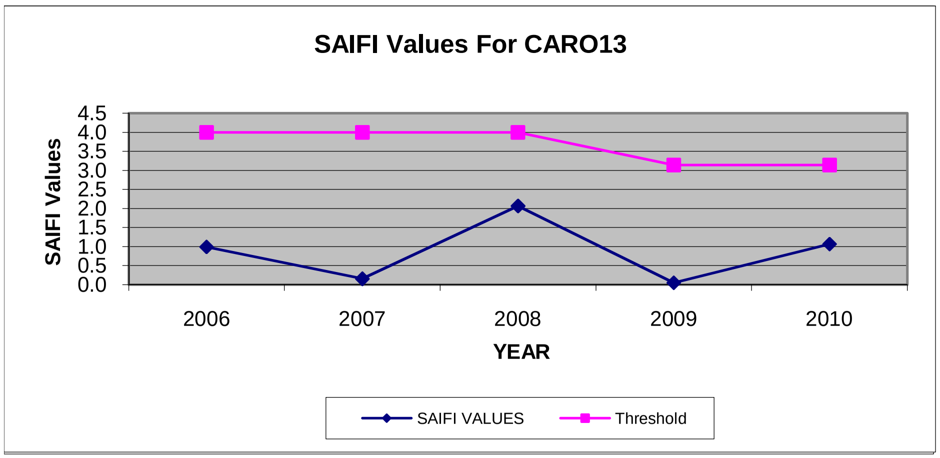


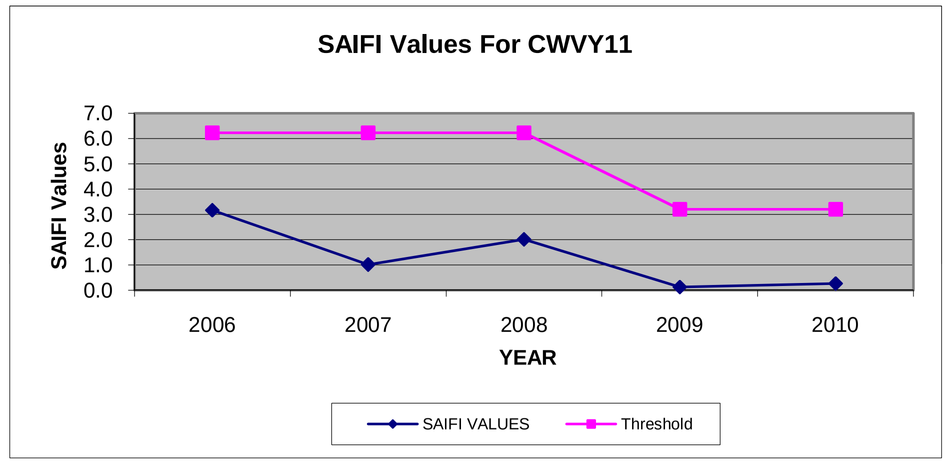


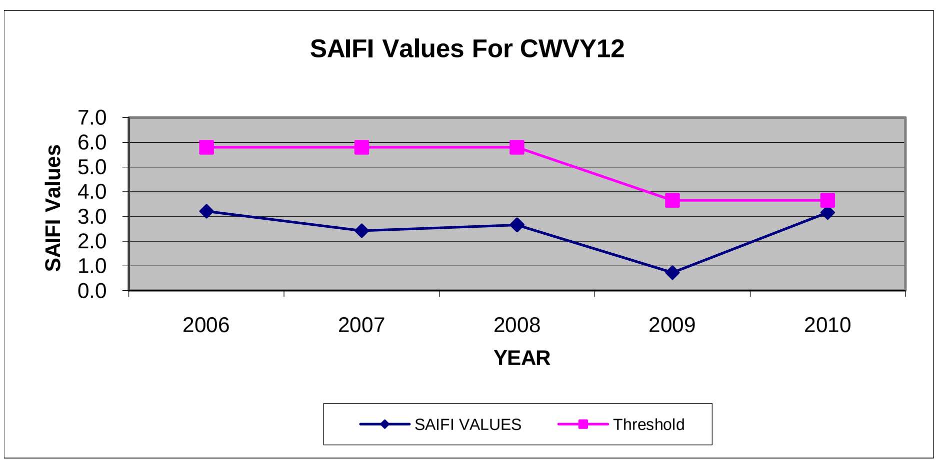
CHARTS - Circuit SAIFI Values

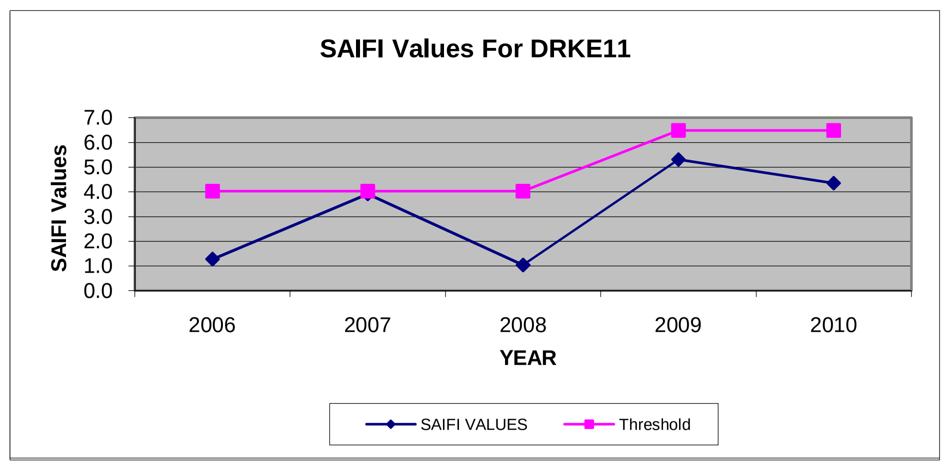


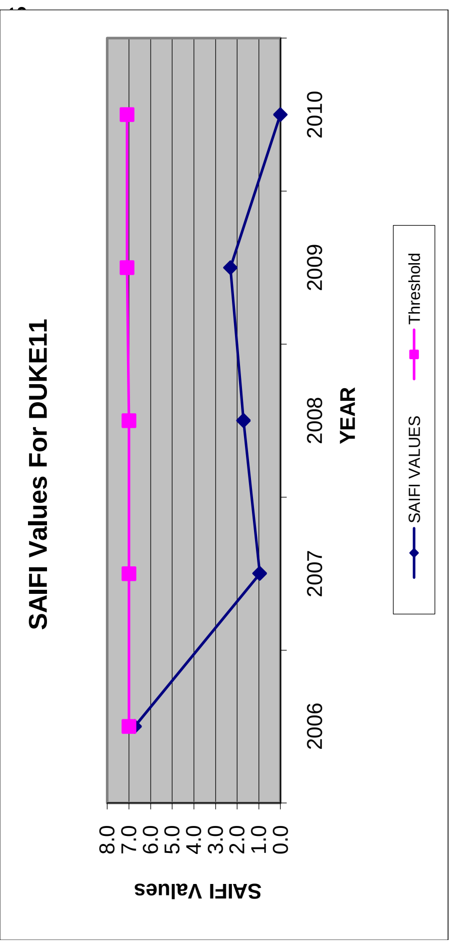











SAIFI Values For DUKE11
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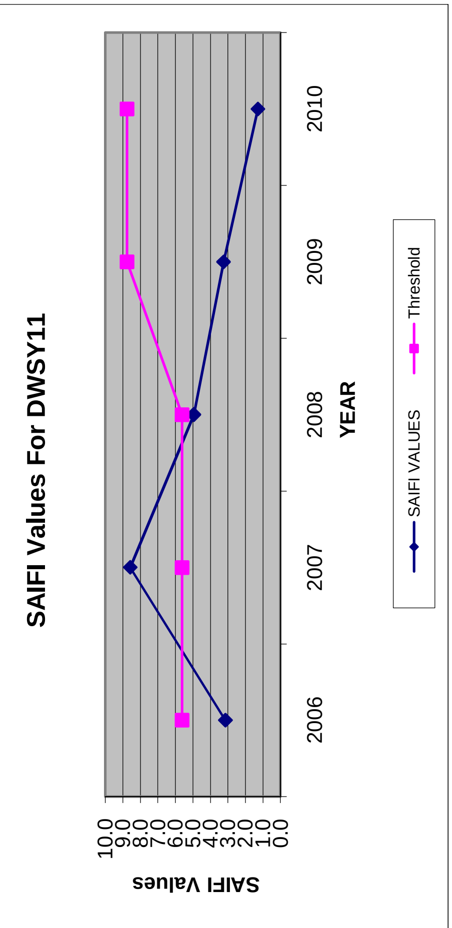
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For DWSY11
SAIFI Values
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9.0
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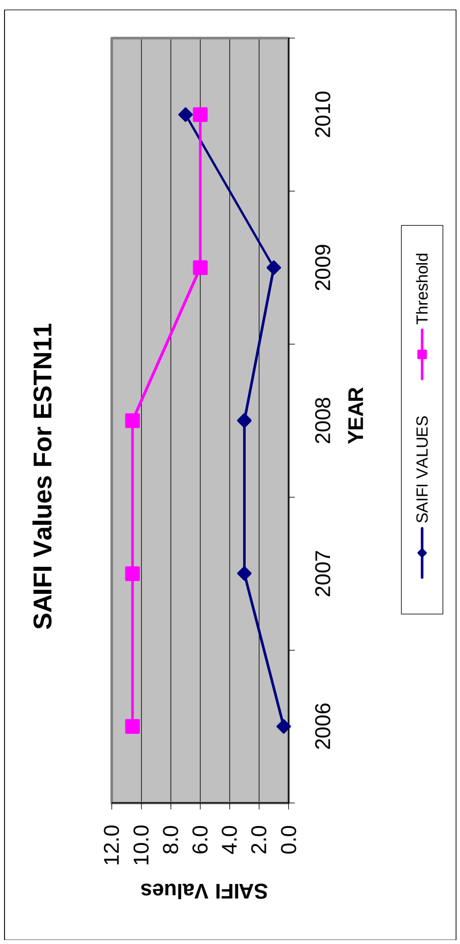
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For ESTN11
SAIFI Values
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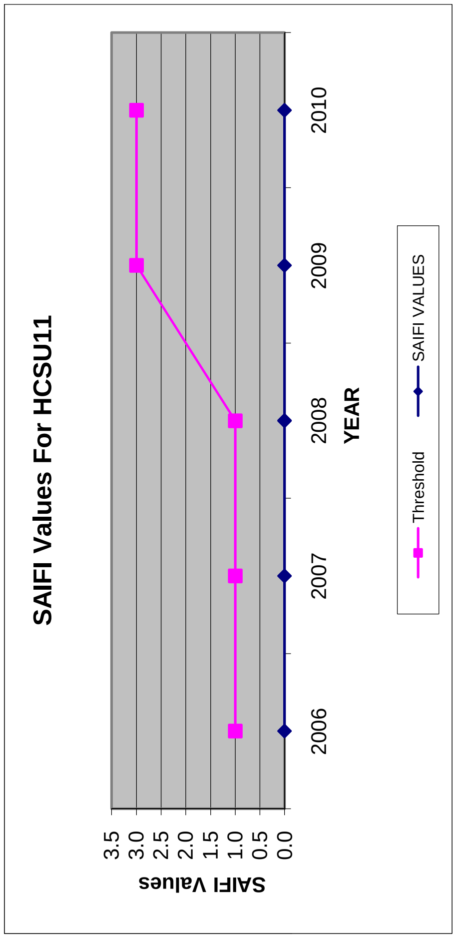
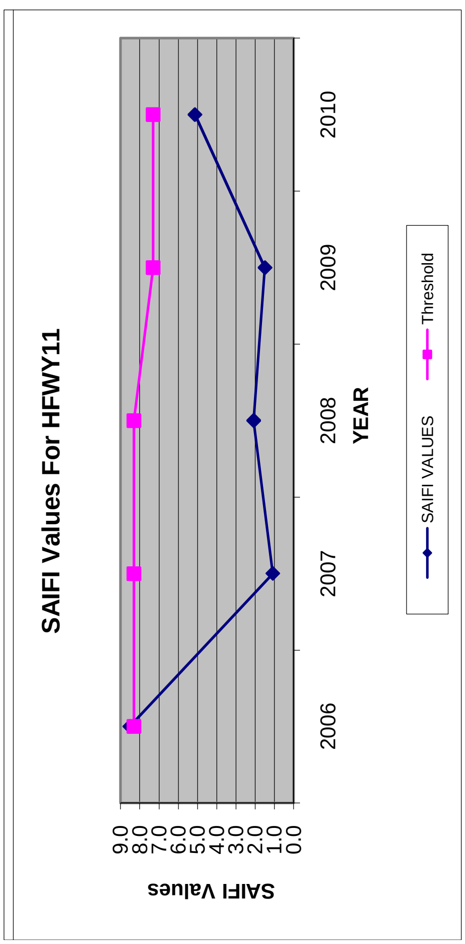
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HCSU11
SAIFI Values
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
Threshold
SAIFI VALUES


SAIFI Values For HFWY11
SAIFI Values
9.0
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7.0
6.0
5.0
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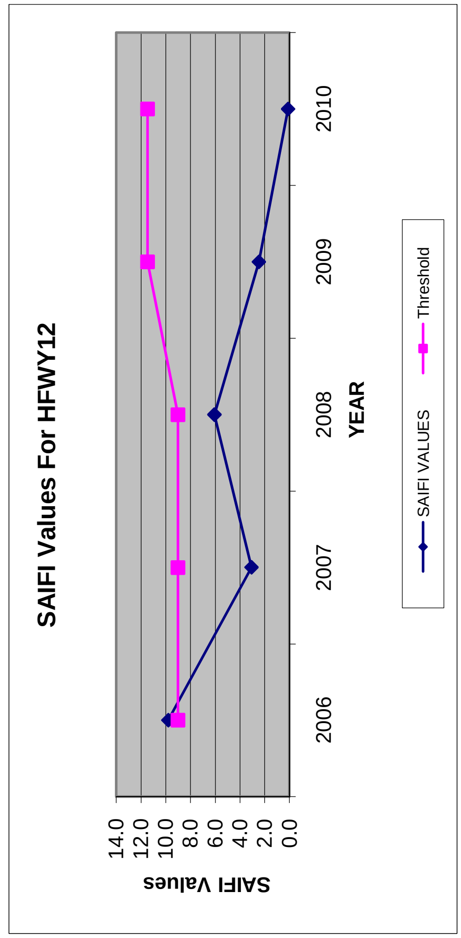
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HFWY12
SAIFI Values
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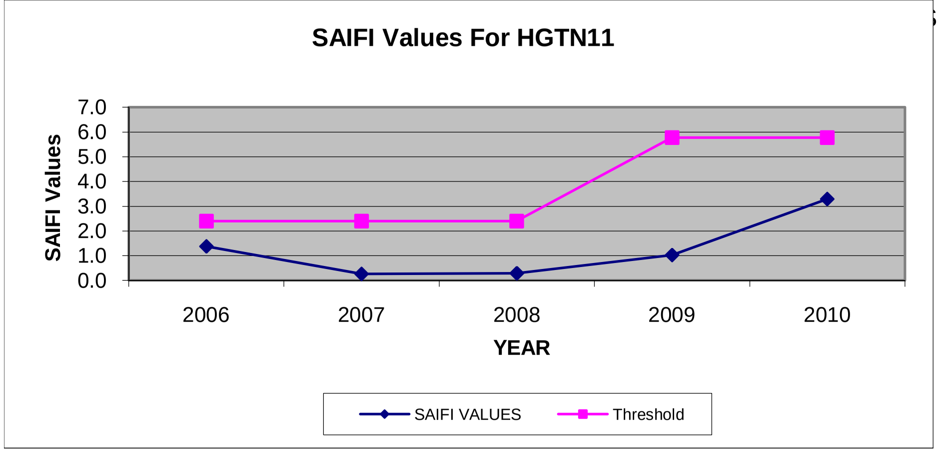
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HGTN11
SAIFI Values
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3.0
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1.0
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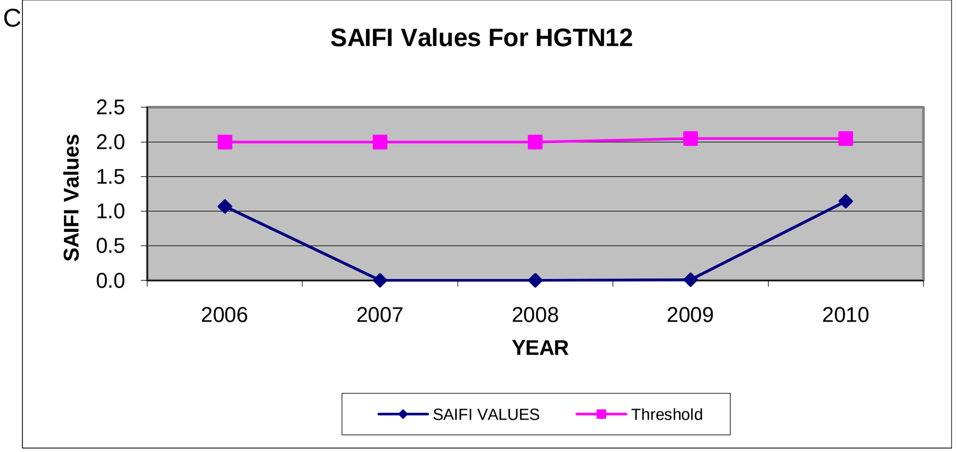
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HGTN12
SAIFI Values
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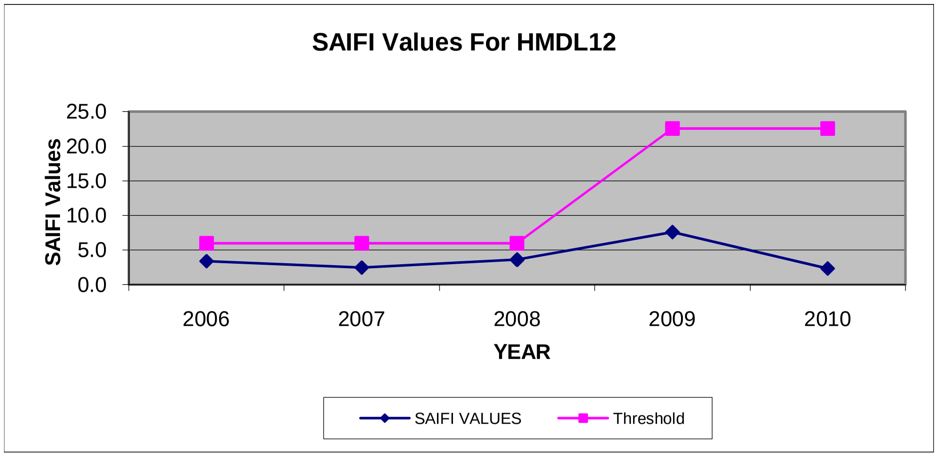
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HMDL12
SAIFI Values
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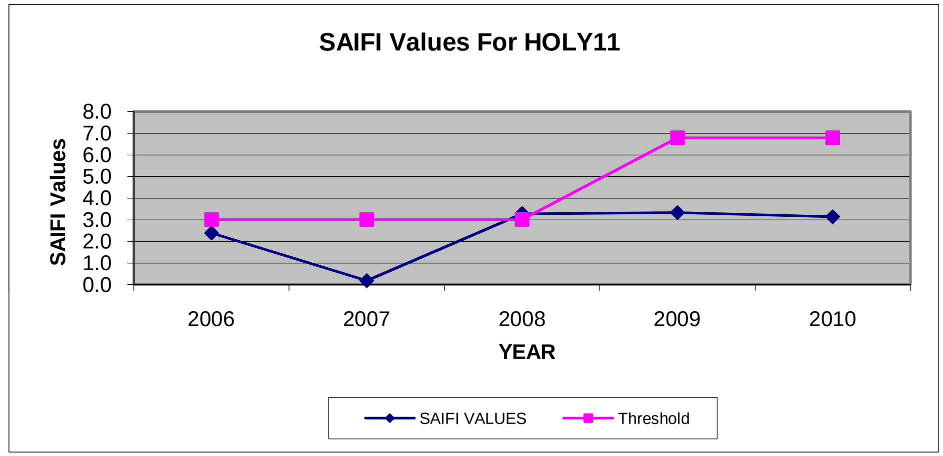
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HOLY11
SAIFI Values
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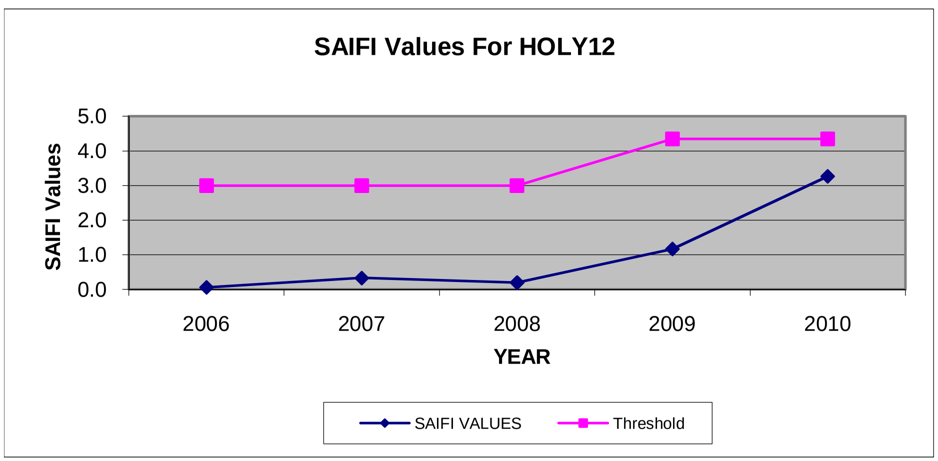
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HOLY12
SAIFI Values
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3.0
2.0
1.0
0.0
2006
2007
2008
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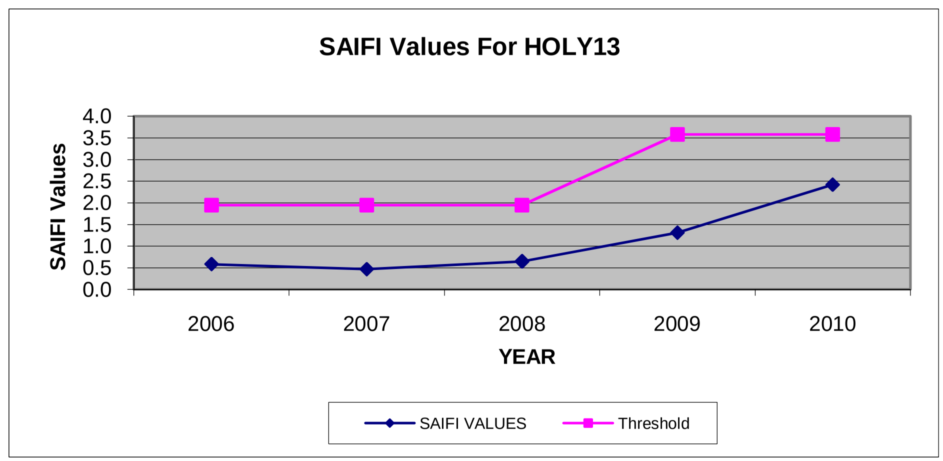
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HOLY13
SAIFI Values
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3.5
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2.5
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1.5
1.0
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0.0
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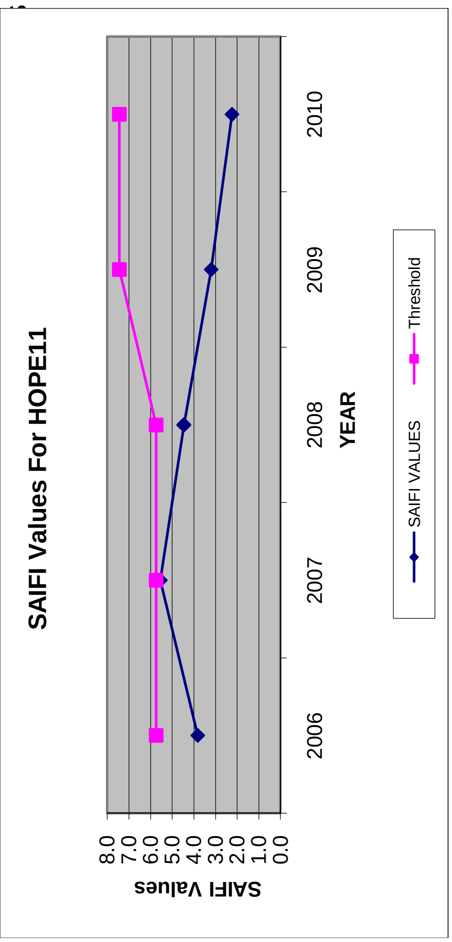
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HOPE11
SAIFI Values
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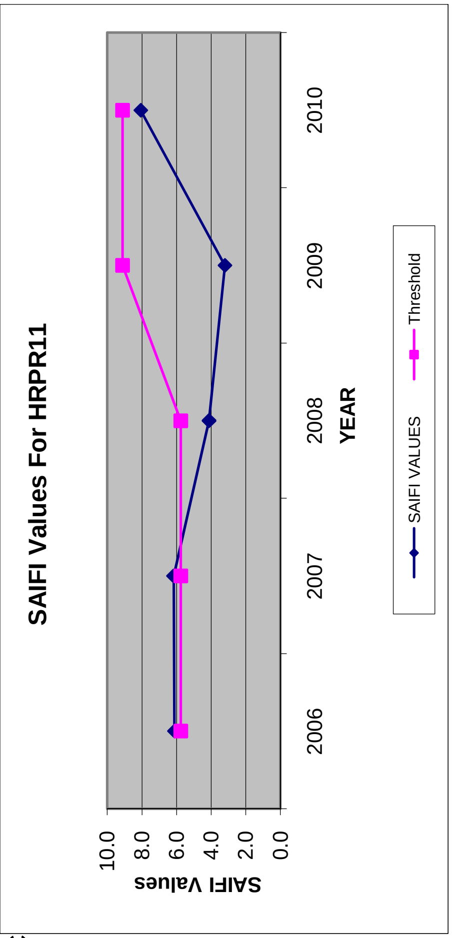
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HRPR11
SAIFI Values
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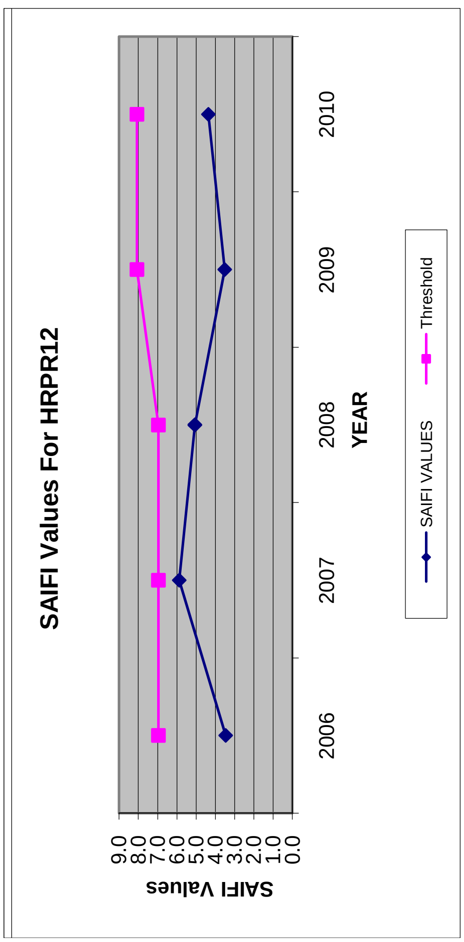
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For HRPR12
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7.0
6.0
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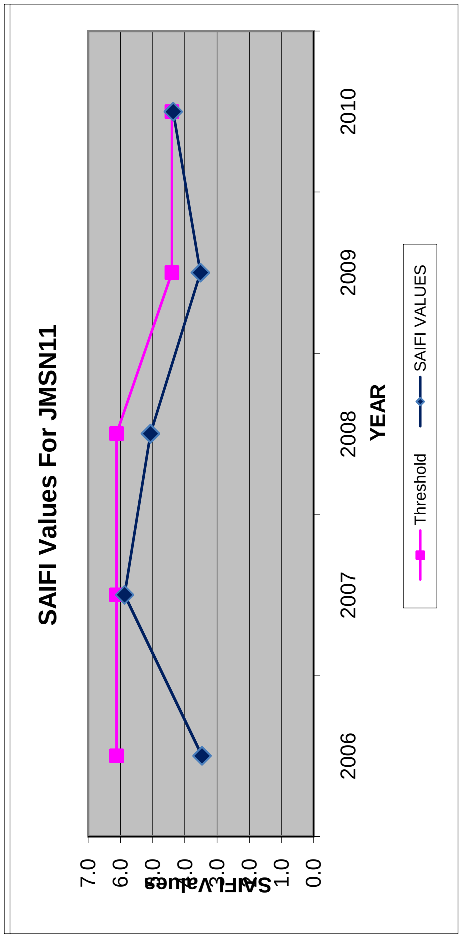
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For JMSN11
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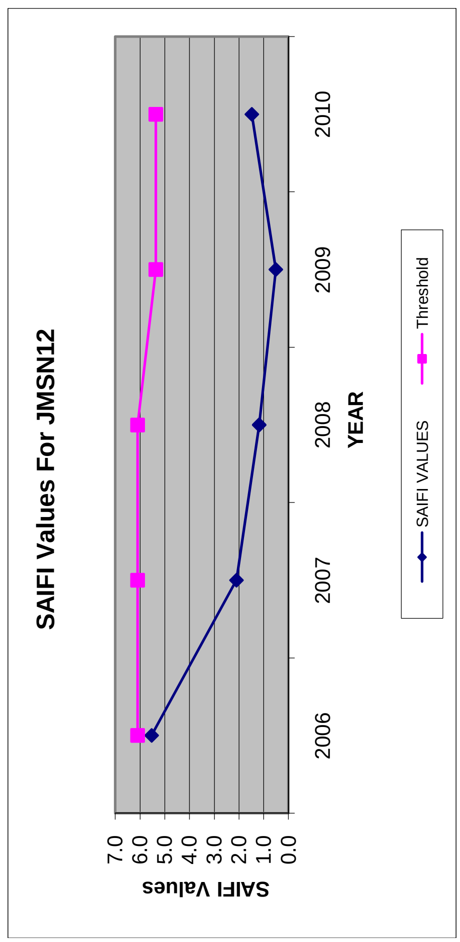
2007
2008
2009
2010
YEAR
Threshold
SAIFI VALUES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SAIFI Values
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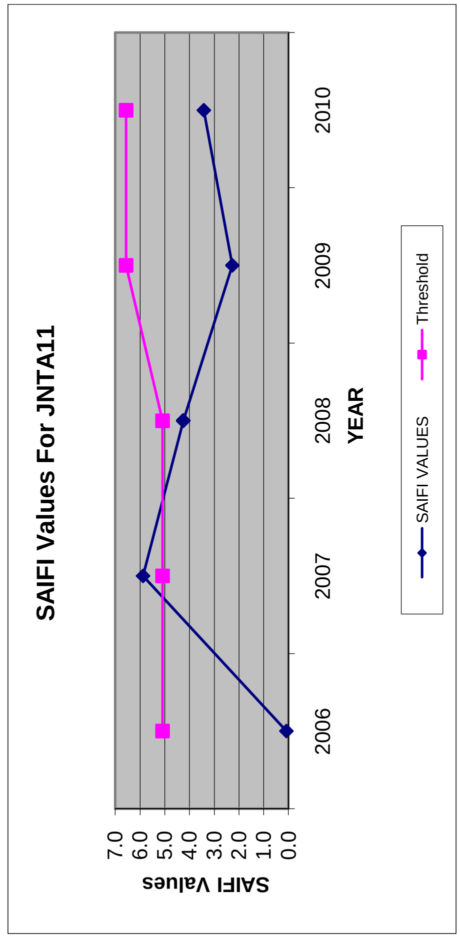
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For JNTA11
SAIFI Values
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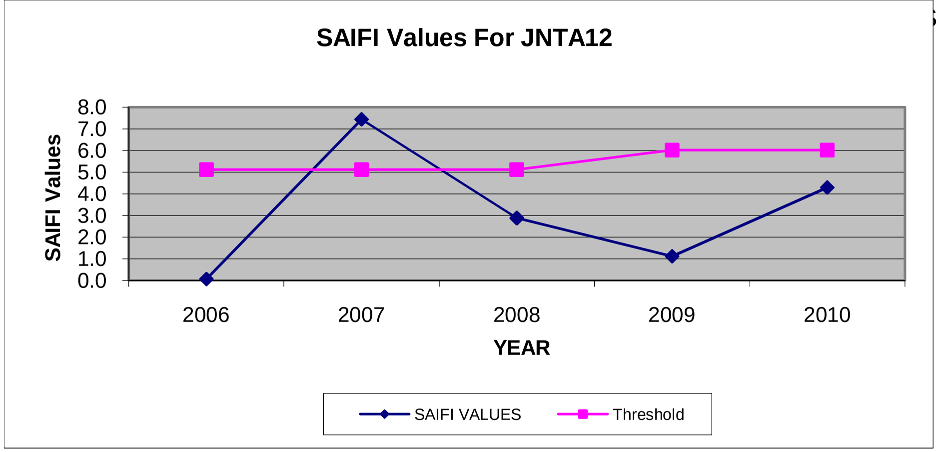
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold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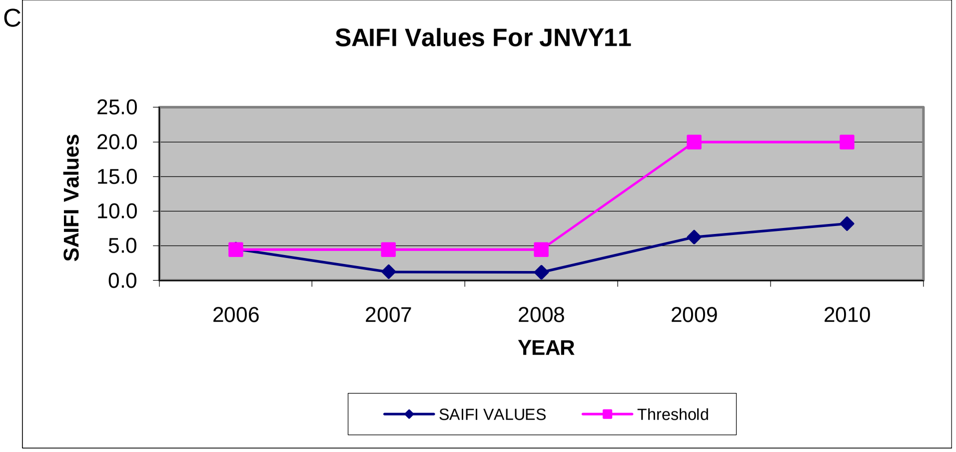
2008
2009
2010
YEAR
SAIFI VALUES
Threshold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SAIFI Values
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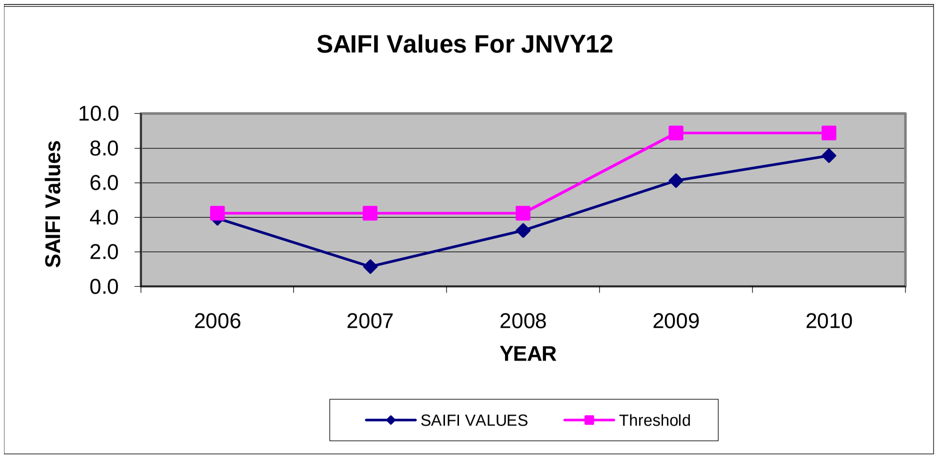
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold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2.0
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2007
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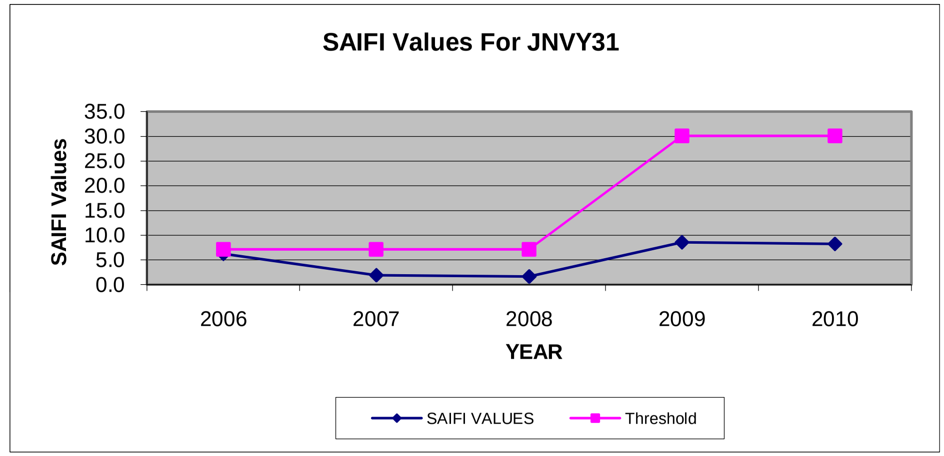
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For JNVY31
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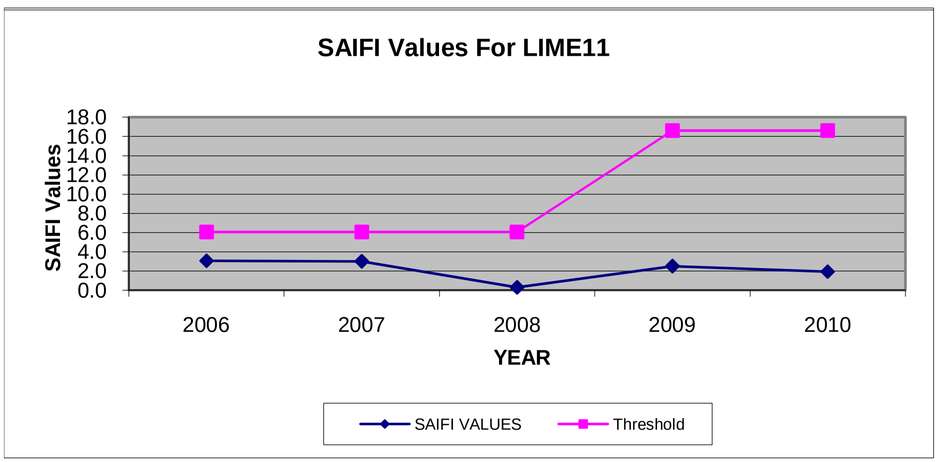
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For LIME11
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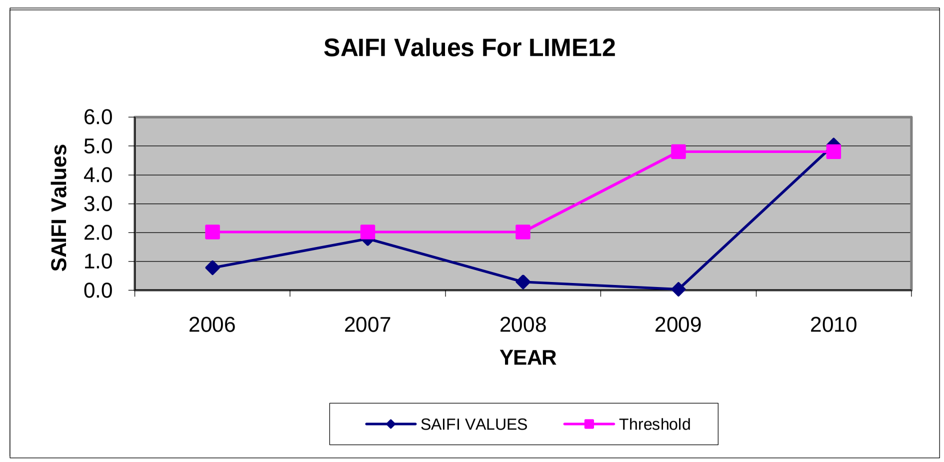
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For LIME12
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2007
2008
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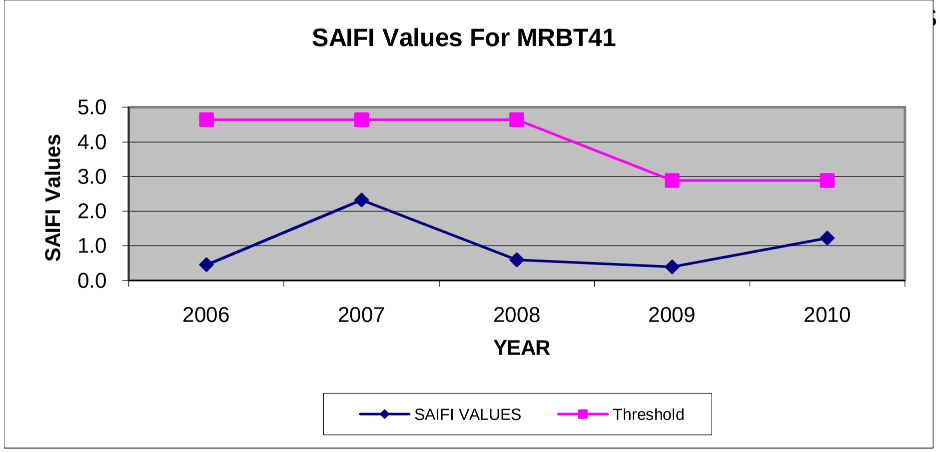
2010
YEAR
SAIFI VALUES
Threshold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2010
YEAR
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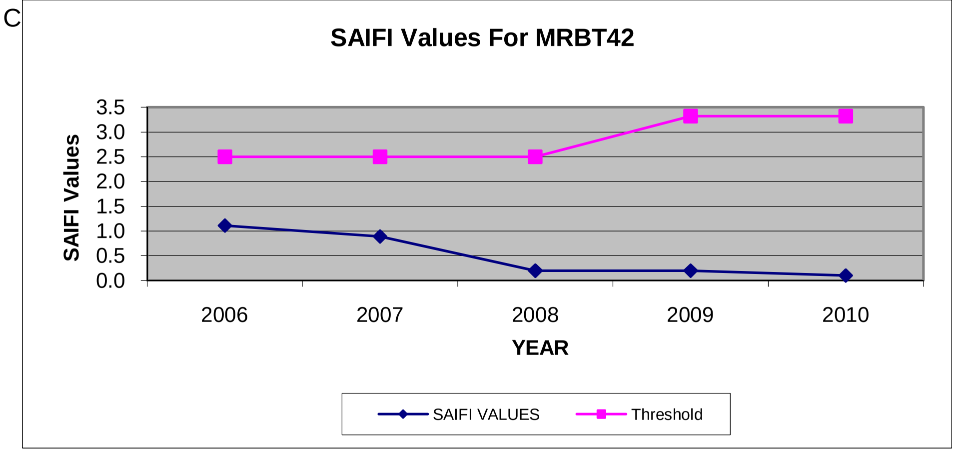
Threshold


SAIFI Values For MRBT42
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YEAR
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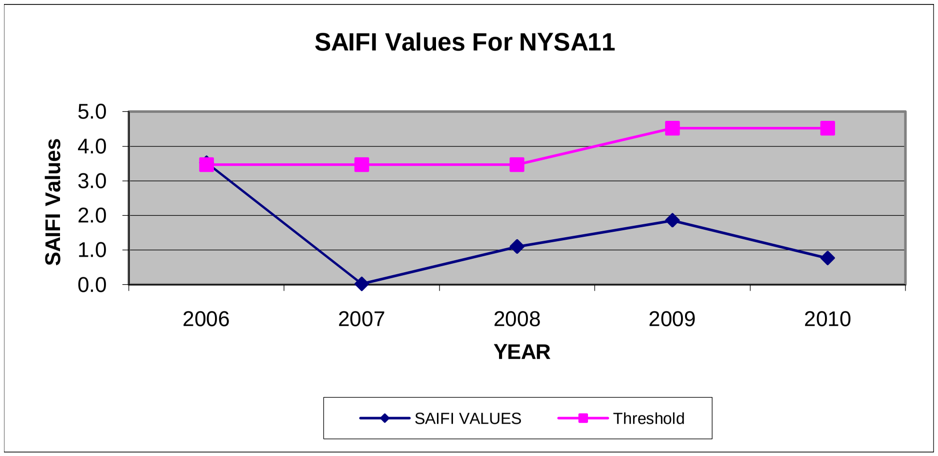
Threshold


SAIFI Values For NYSA11
SAIFI Values
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2007
2008
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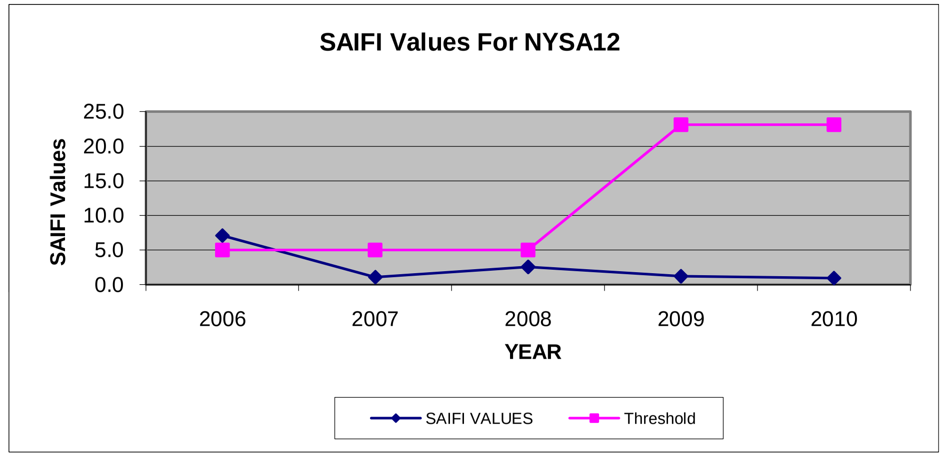
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For NYSA12
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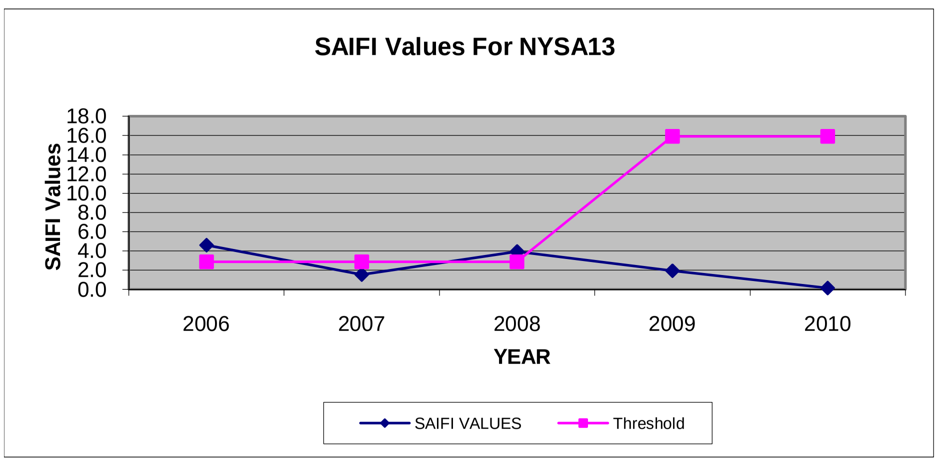
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For NYSA13
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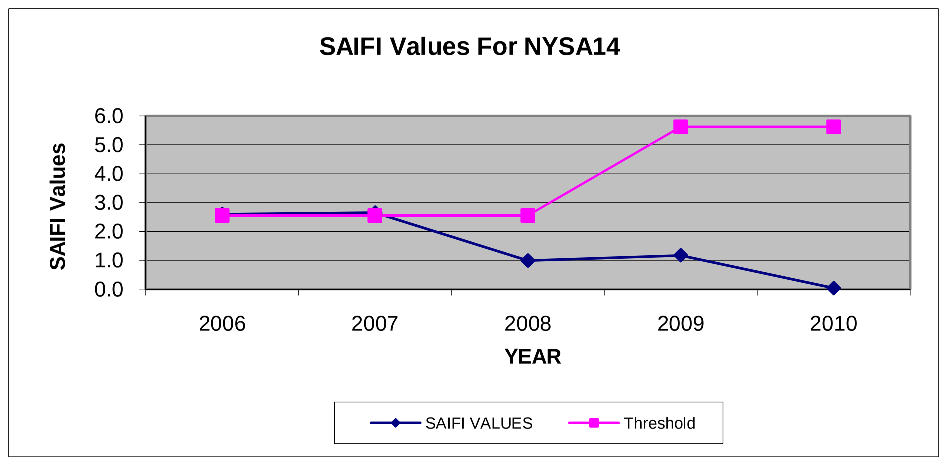
YEAR
SAIFI VALUES
Threshold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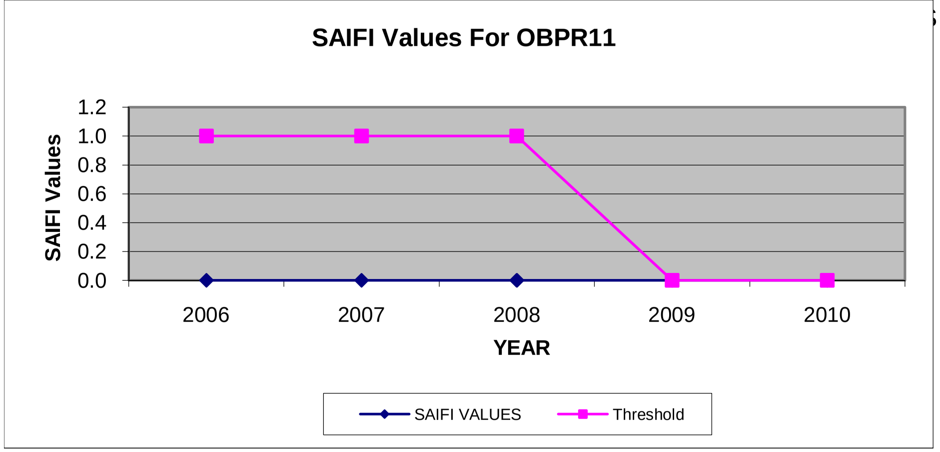
YEAR
SAIFI VALUES
Threshold


SAIFI Values For OBPR11
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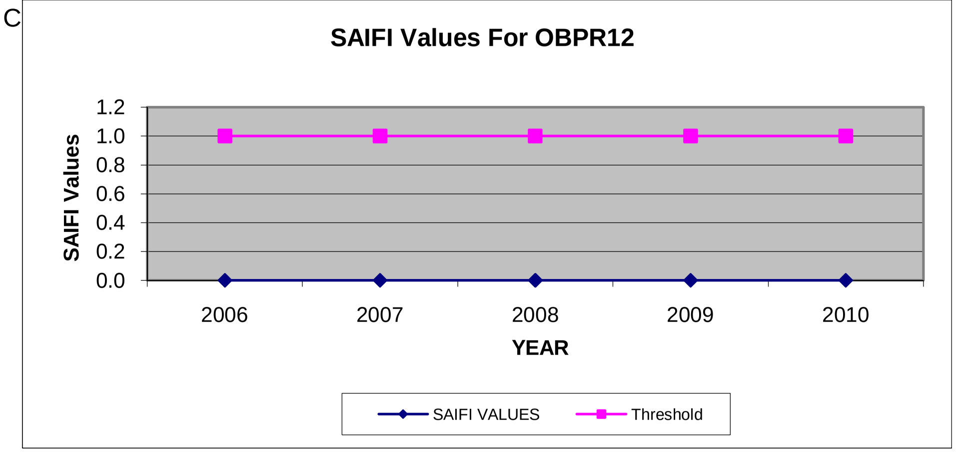
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For OBPR12
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YEAR
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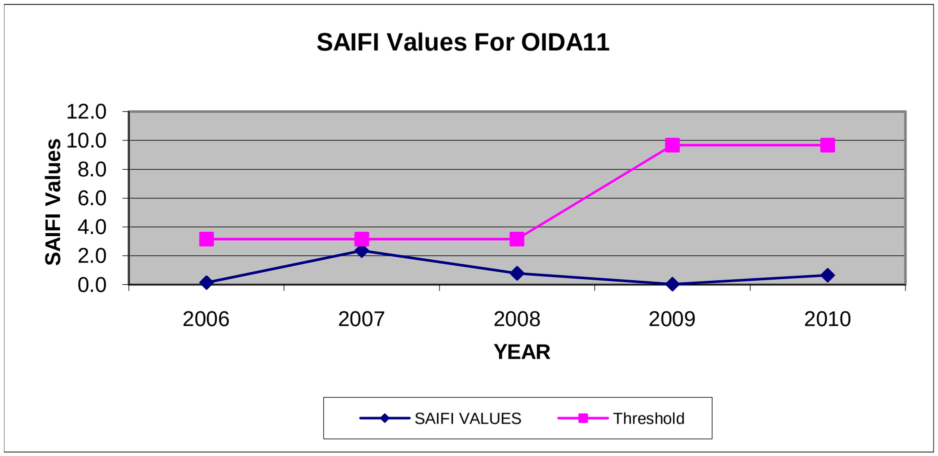
Threshold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YEAR
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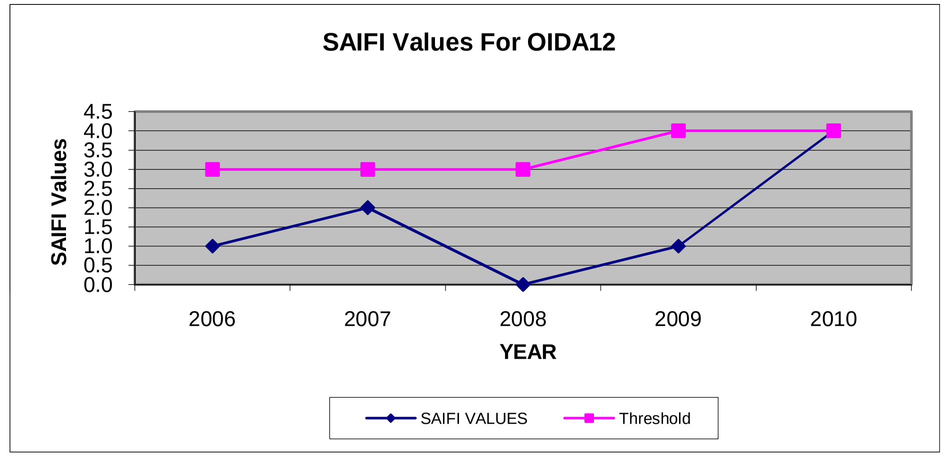
Threshold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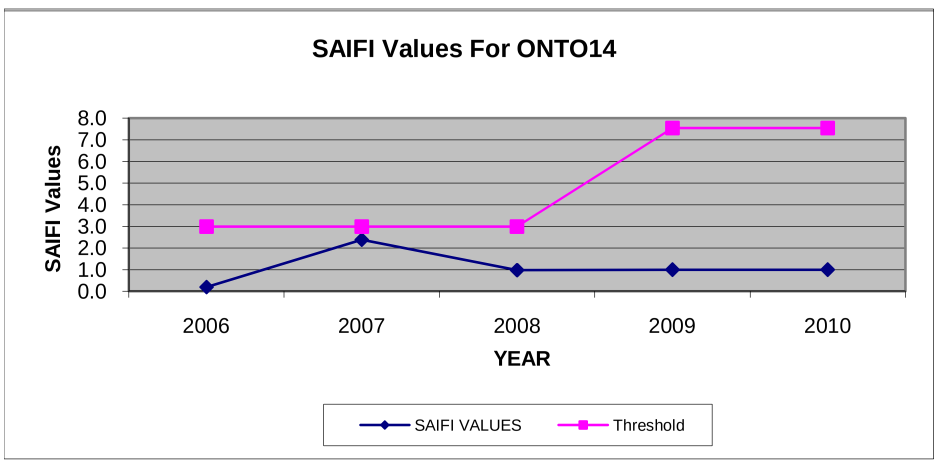
YEAR
SAIFI VALUES
Threshold


SAIFI Values For ONTO14
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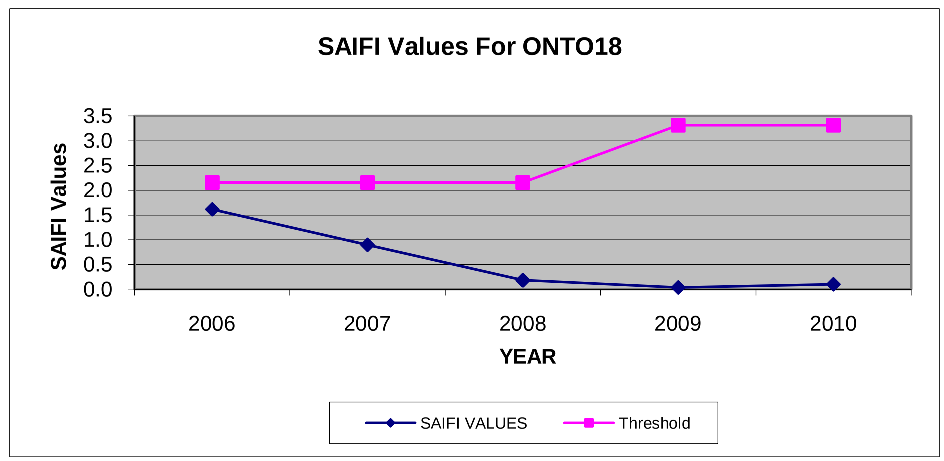
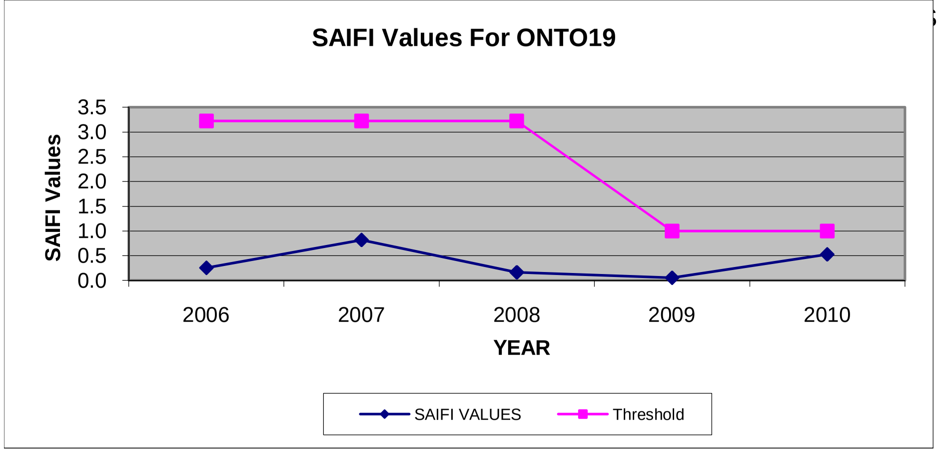
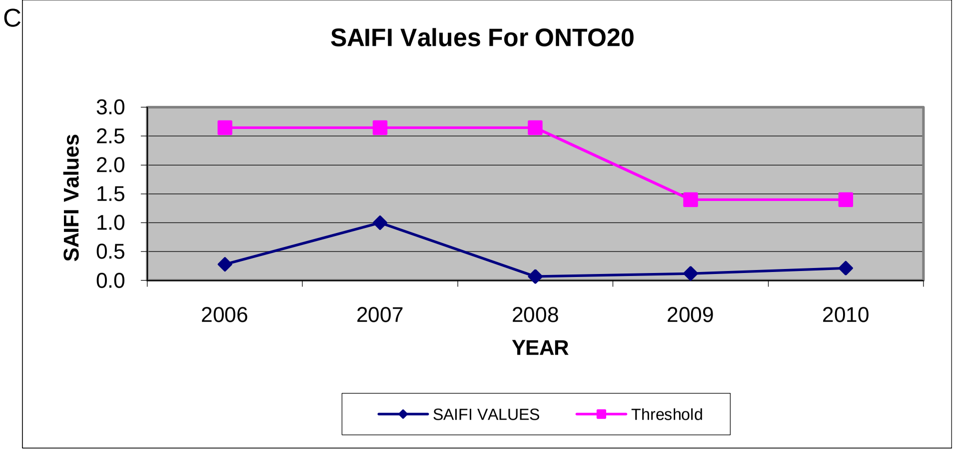
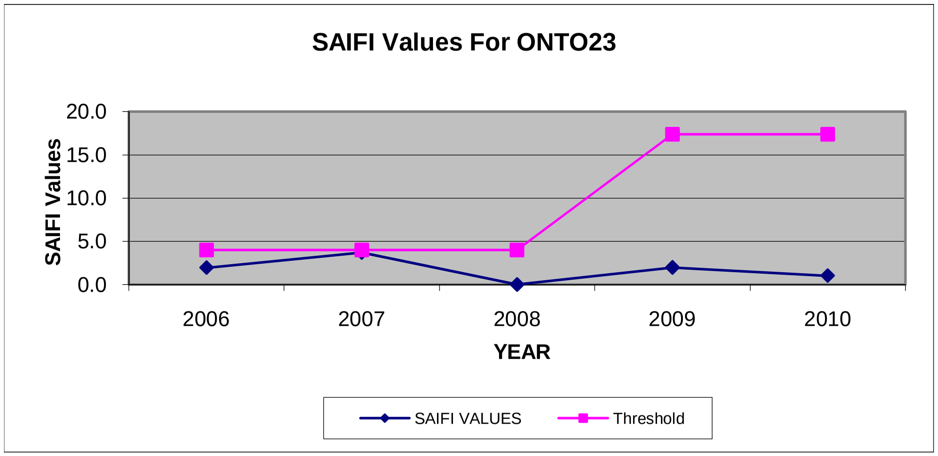
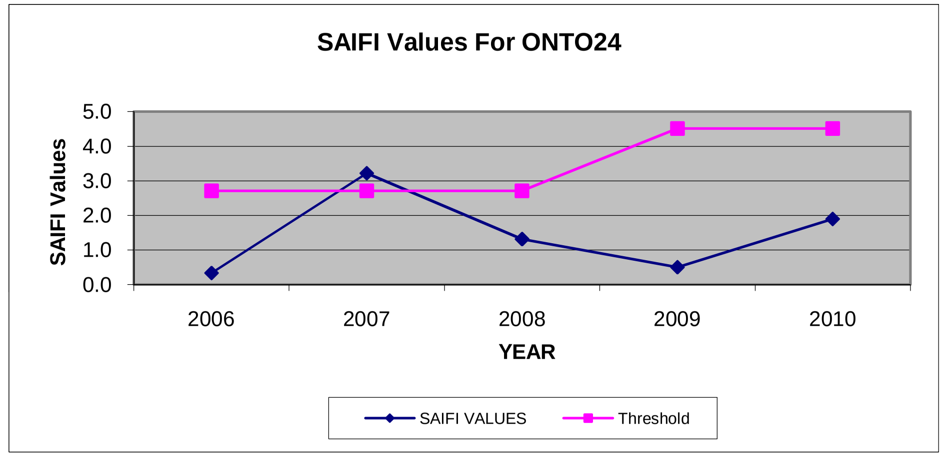
2010
YEAR
SAIFI VALUES
Threshold

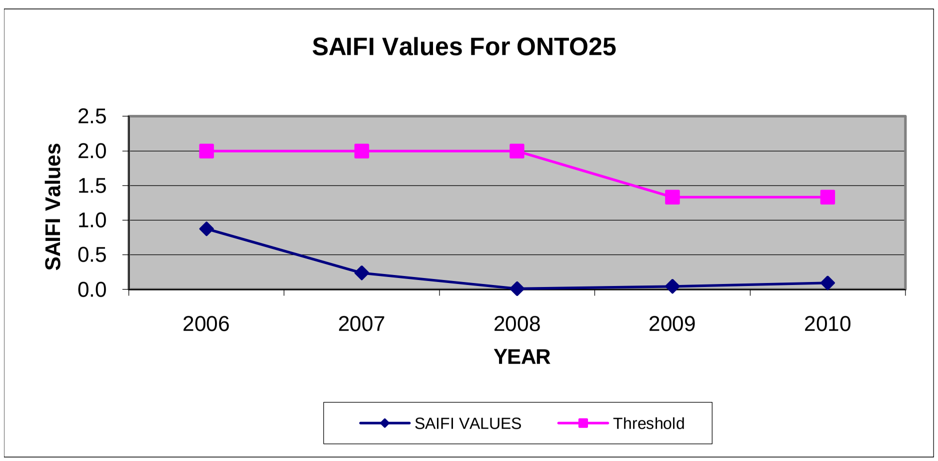

SAIFI Values For ONTO18
SAIFI Values
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For ONTO19
SAIFI Values
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For ONTO20
SAIFI Values
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For ONTO23
SAIFI Values
20.0
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For ONTO24
SAIFI Values
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For ONTO25
SAIFI Values
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1.5
1.0
0.5
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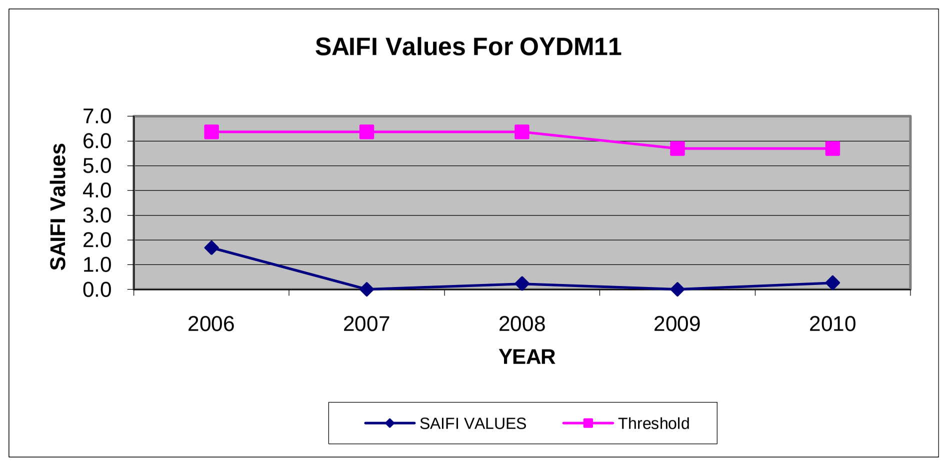
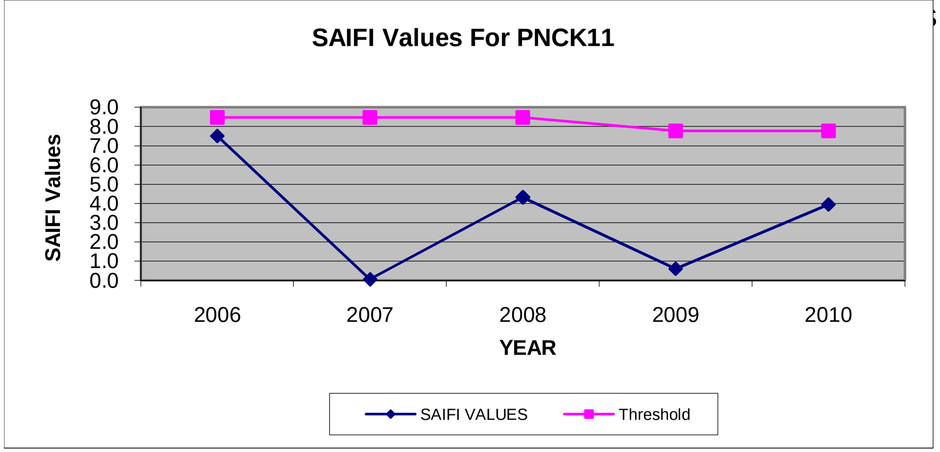
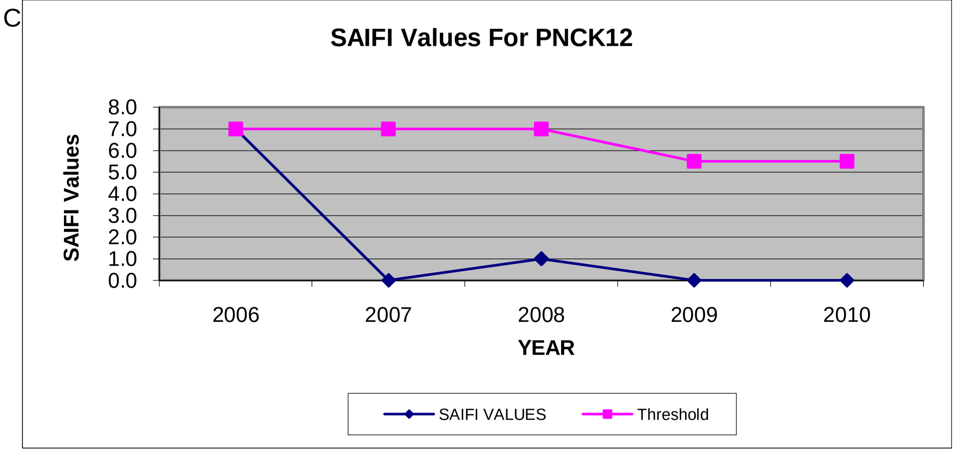
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For OYDM11
SAIFI Values
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For PNCK11
SAIFI Values
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For PNCK12
SAIFI Values
8.0
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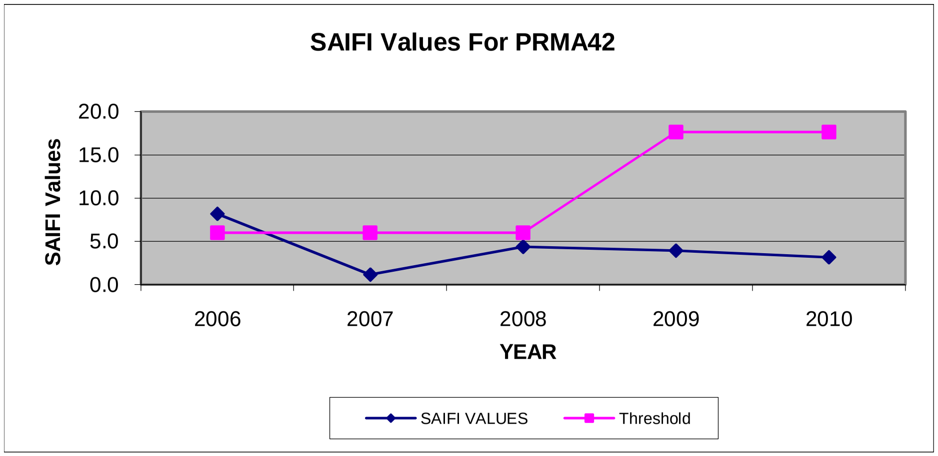
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For PRMA42
SAIFI Values
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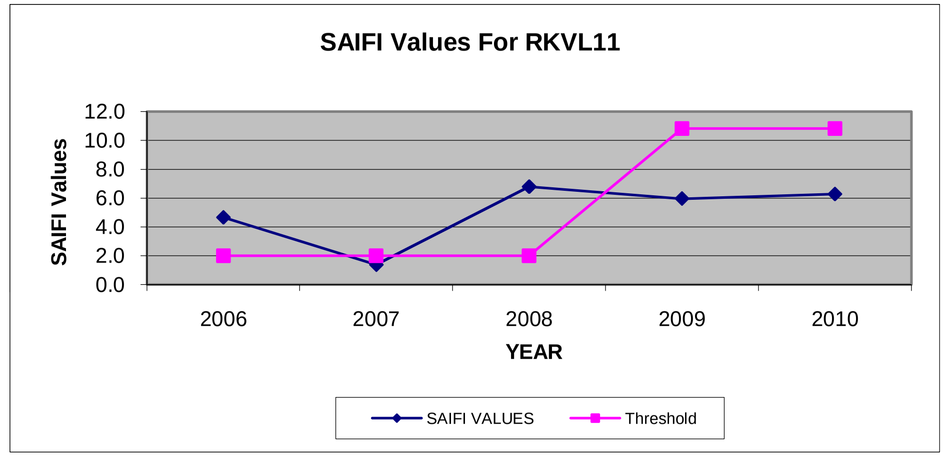
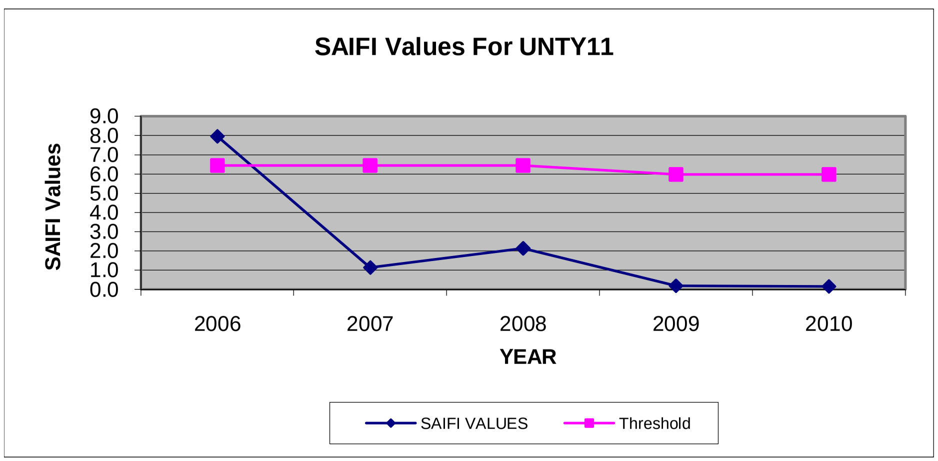
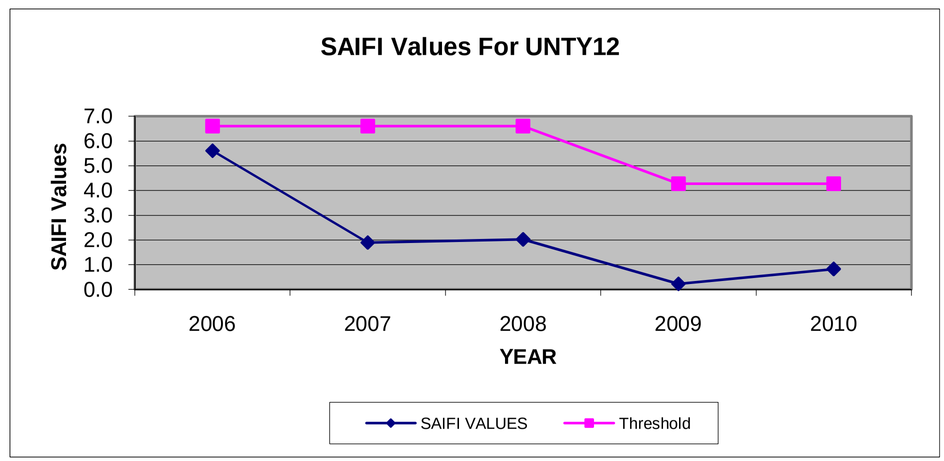
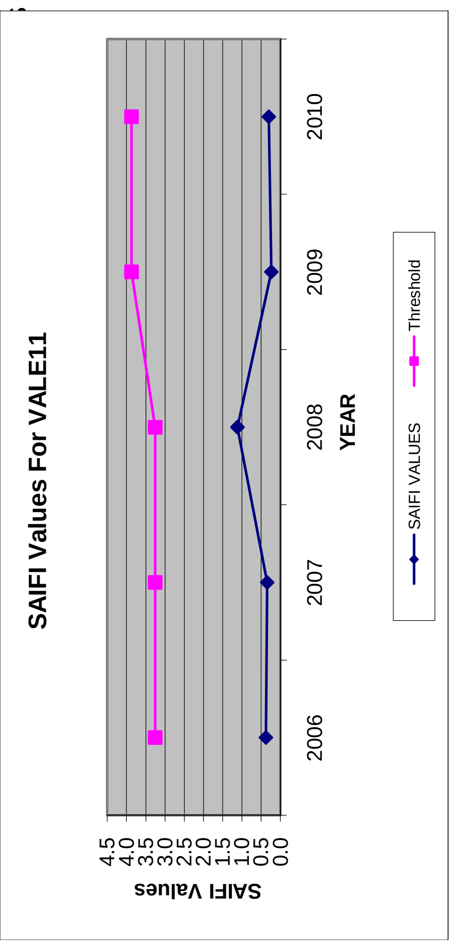
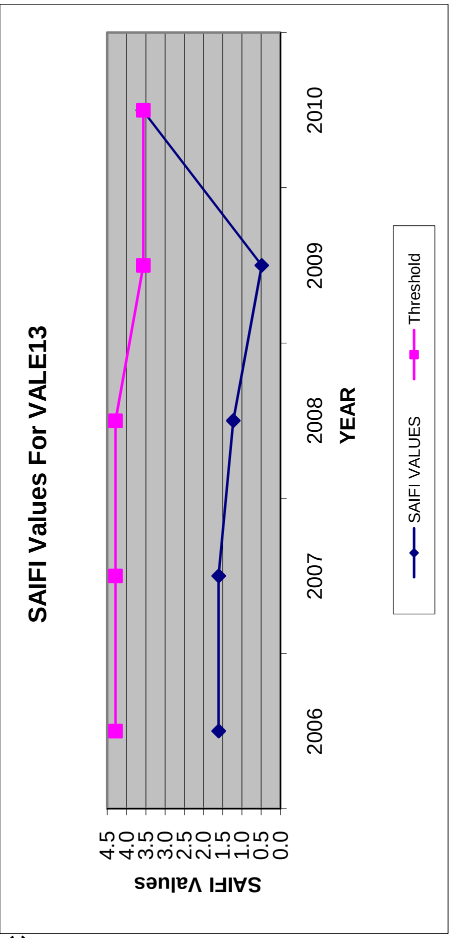
15.0
10.0
5.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold

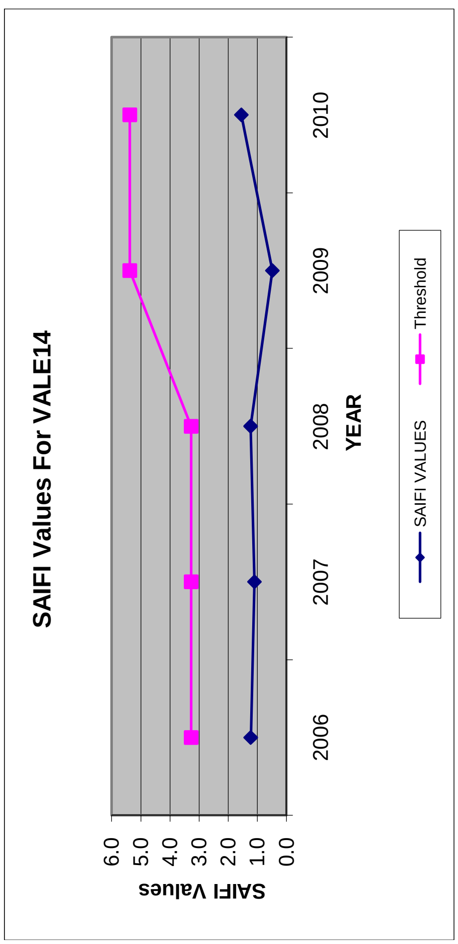

SAIFI Values For RKVL11
SAIFI Values
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold

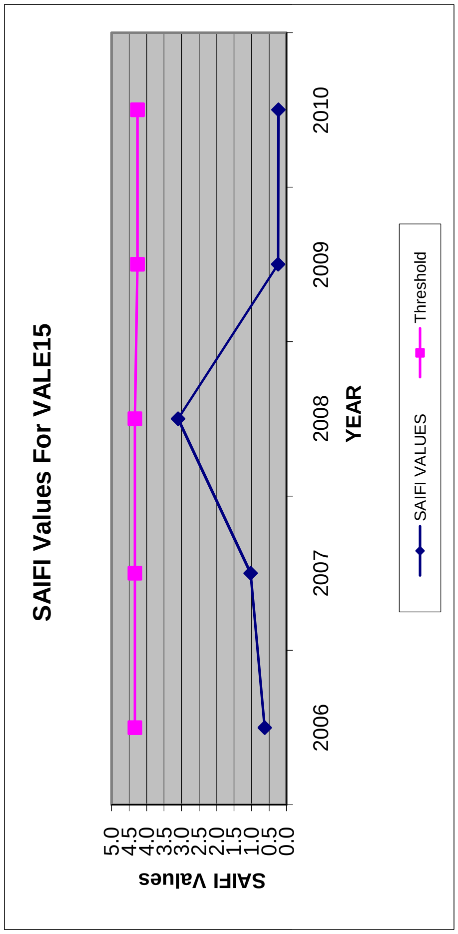

SAIFI Values For UNTY11
SAIFI Values
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold

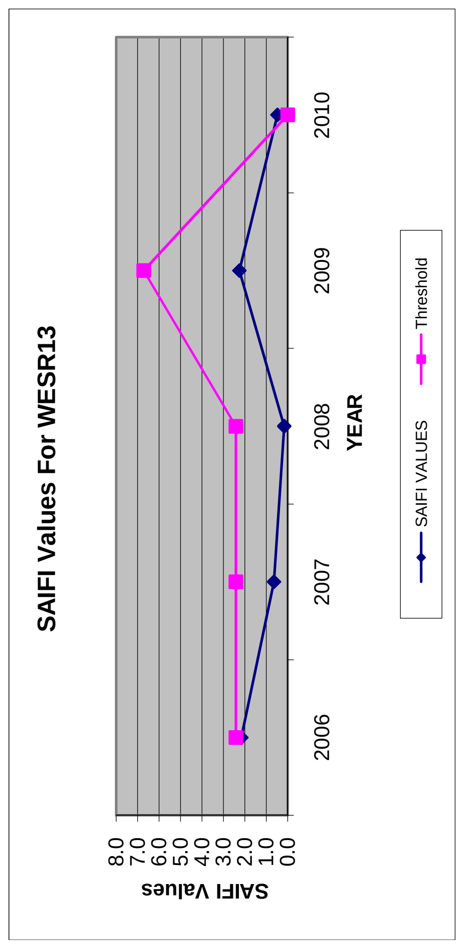

SAIFI Values For UNTY12
SAIFI Values
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For VALE11
SAIFI Values
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For VALE13
SAIFI Values
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For VALE14
SAIFI Values
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For VALE15
SAIFI Values
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For WESR13
SAIFI Values
8.0
7.0
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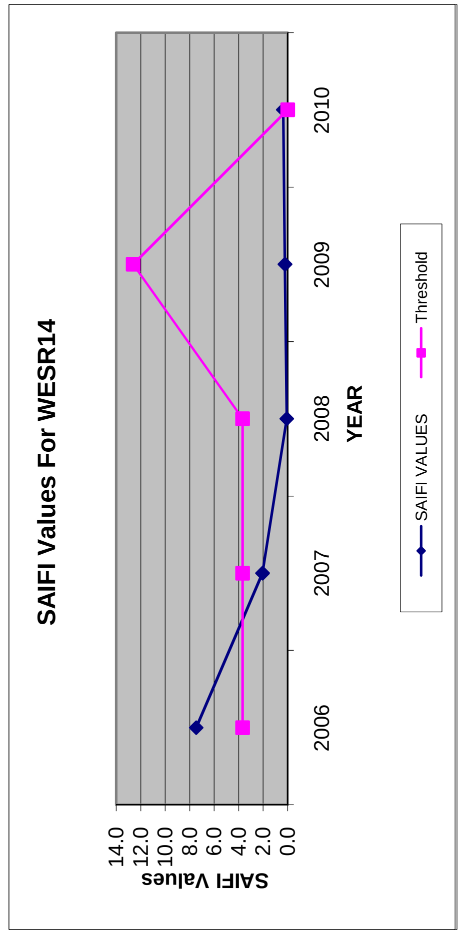
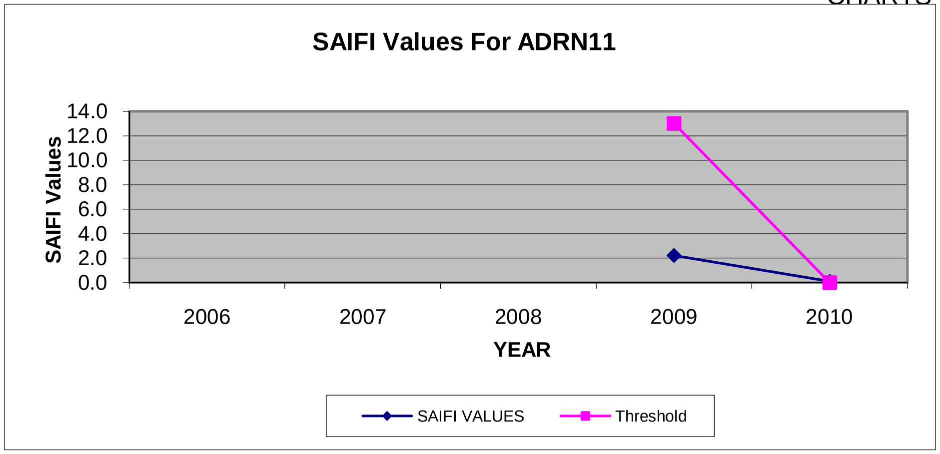
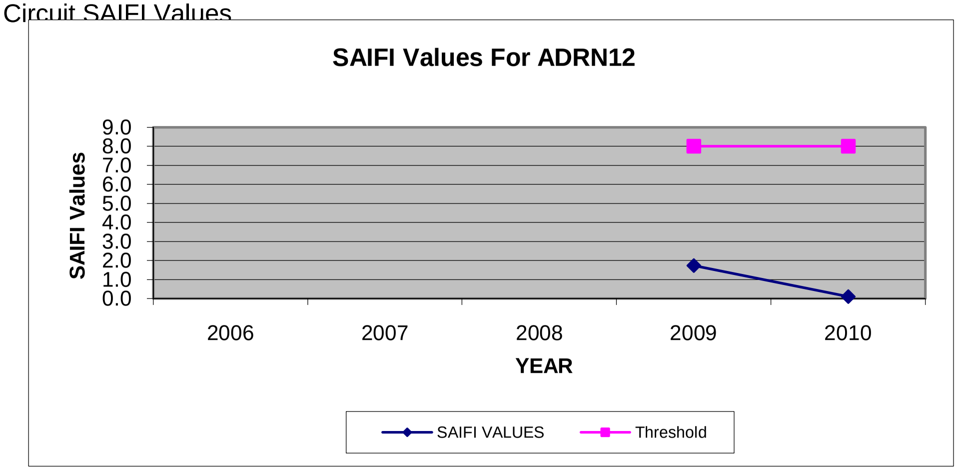
4.0
3.0
2.0
1.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold


SAIFI Values For WESR14
SAIFI Values
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
YEAR
SAIFI VALUES
Threshold

CHARTS - Circuit SAIFI Values





5 Years of Sustained Interruption Causes

TABLE 5

CAUSE	NUMBER of SUSTAINED INTERRUPTIONS 2006	2007	2008	2009	2010	PERCENT of TOTAL SUSTAINED INTERRUPTIONS 2006	2007	2008	2009	2010
ADVERSE ENVIRONMENT	15	16	2	12	**99**	2.34	3.21	0.31	2.09	**11.47%**
ADVERSE WEATHER	134	59	48	40	****0**	20.94	11.82	7.37	6.96	**0.00%**
CUSTOMERS EQUIPMENT	*60	*42	*15	*9	***7**	0.00	0.00	0.00	0.00	**0.00%**
EQUIPMENT FAILURES	118	80	151	110	**216**	18.44	16.03	23.20	19.13	**25.03%**
FOREIGN INTERFERENCE	74	71	119	99	**63**	11.56	14.23	18.28	17.22	**7.30%**
HUMAN ELEMENT	7	21	36	7	**20**	1.09	4.21	5.53	1.22	**2.32%**
LIGHTNING	18	3	9	19	**16**	2.81	0.60	1.38	3.30	**1.85%**
LOSS OF SUPPLY	5	13	38	19	**26**	0.78	2.61	5.84	3.30	**3.01%**
MAJOR EVENTS	0	0	0	0	**0**	0.00	0.00	0.00	0.00	**0.00%**
SCHEDULED OUTAGES	69	91	112	64	**155**	10.78	18.24	17.20	11.13	**17.96%**
TREE CONTACTS	46	27	22	25	**49**	7.19	5.41	3.38	4.35	**5.68%**
UNKNOWN	154	118	114	180	**219**	24.06	23.65	17.51	31.30	**25.38%**
TOTAL	640	499	651	575	**870**	100.00	100.00	100.00	100.00	**100.00%**

*** = Not Included in Calculations**

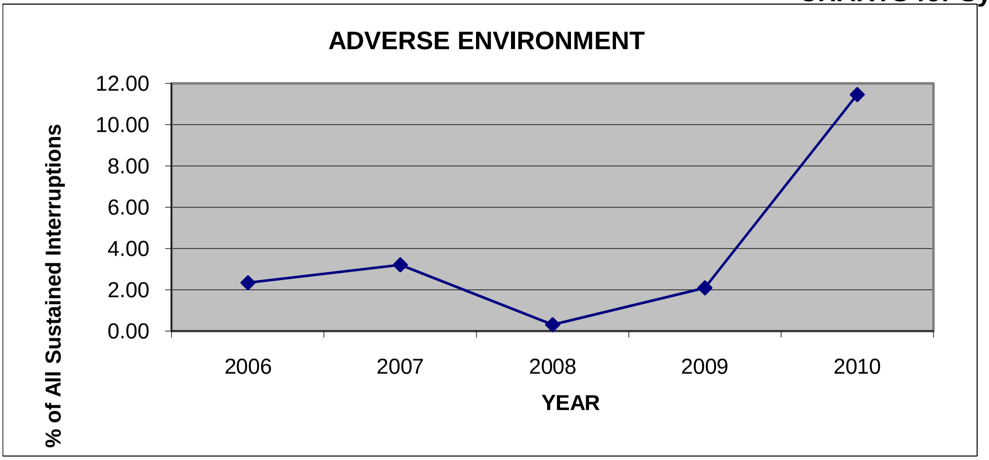
****= On September 1 2010 we implemented new cause codes in an effort to better determine "Root Cause" of ourages. However, this change impacted our ability to filter for 2010 "Adverse Weather". We have made necessary adjustments to allow filtering for "adverse weather" in 2011 and byond**

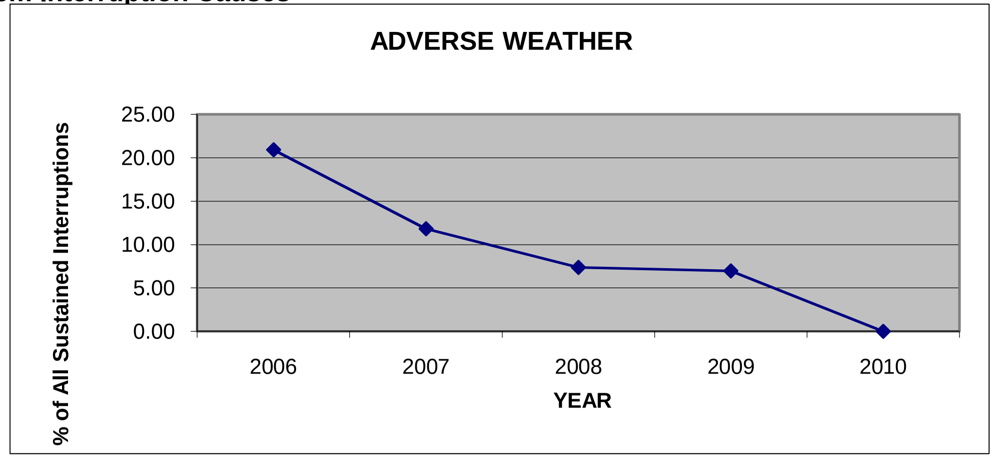
2010 Sustained Interruption Cause Ranking

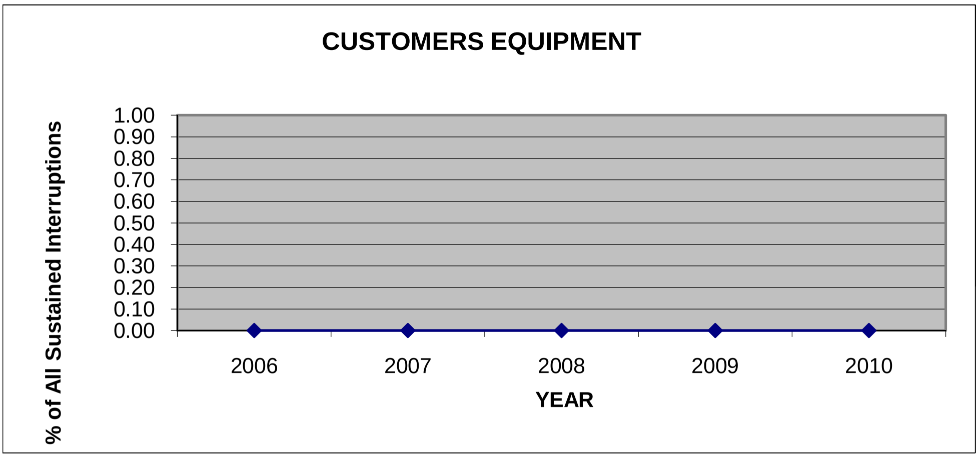
TABLE 6

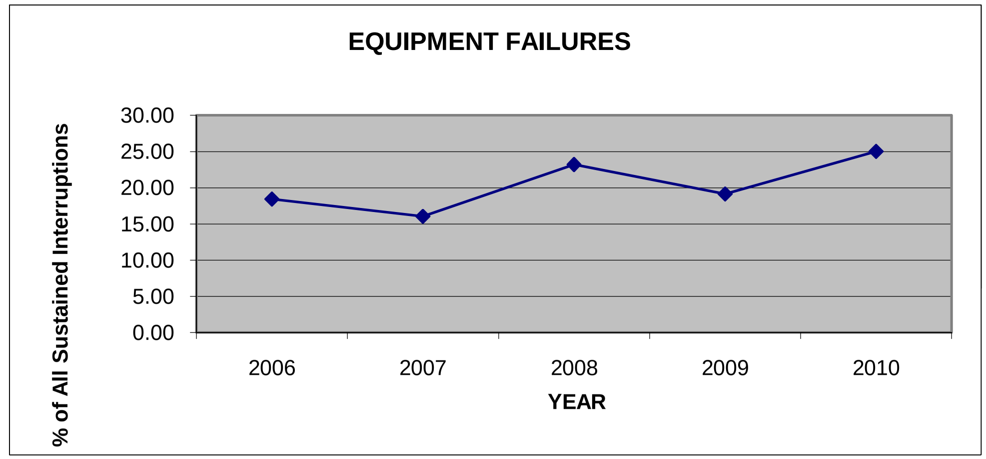
CAUSE	OCCURRENCES	CUSTOMER HOURS OUT	OCCURRENCES RANKING	HOURS OUT RANKING
ADVERSE ENVIRONMENT	99	5456.86	4	5
ADVERSE WEATHER	0		0	0
CUSTOMERS EQUIPMENT	7	54.49	10	10
EQUIPMENT FAILURES	216	39324.85	2	1
FOREIGN INTERFERENCE	63	3866.69	5	6
HUMAN ELEMENT	20	1819.99	8	8
LIGHTNING	16	510.20	9	9
LOSS OF SUPPLY	26	2331.13	7	7
MAJOR EVENTS	0	0.00	11	11
SCHEDULED OUTAGES	155	13185.62	3	3
TREE CONTACTS	49	7322.43	6	4
UNKNOWN	219	17613.06	1	2
TOTAL	870	91485.31		

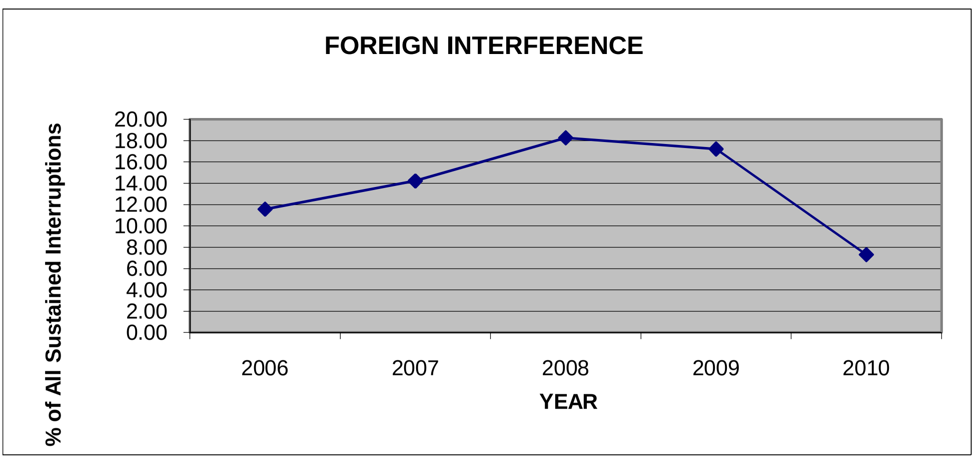
CHARTS for System Interruption Causes

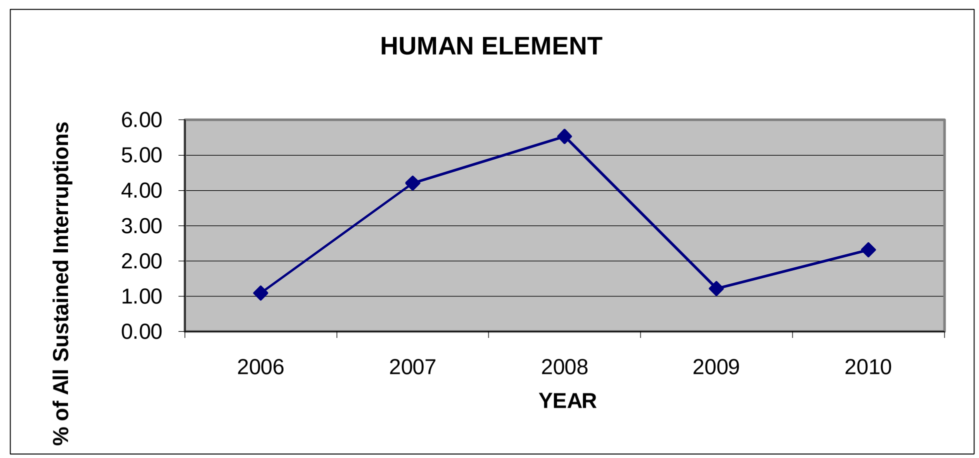




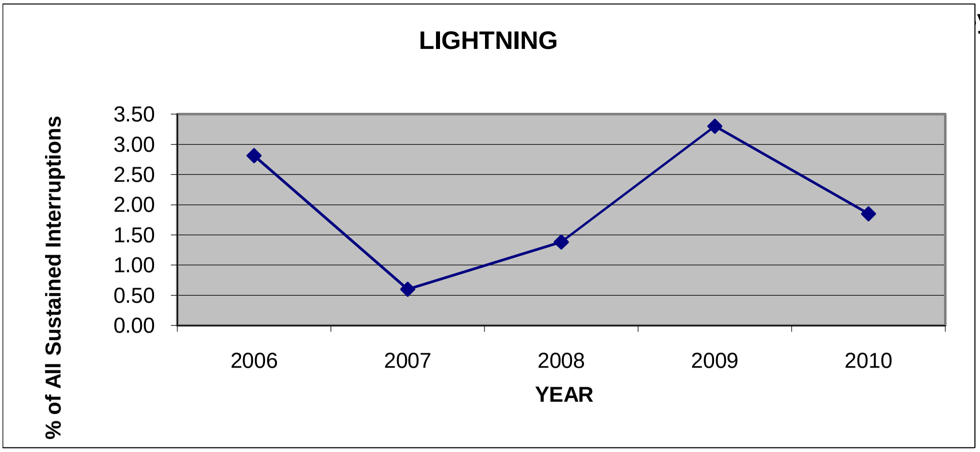


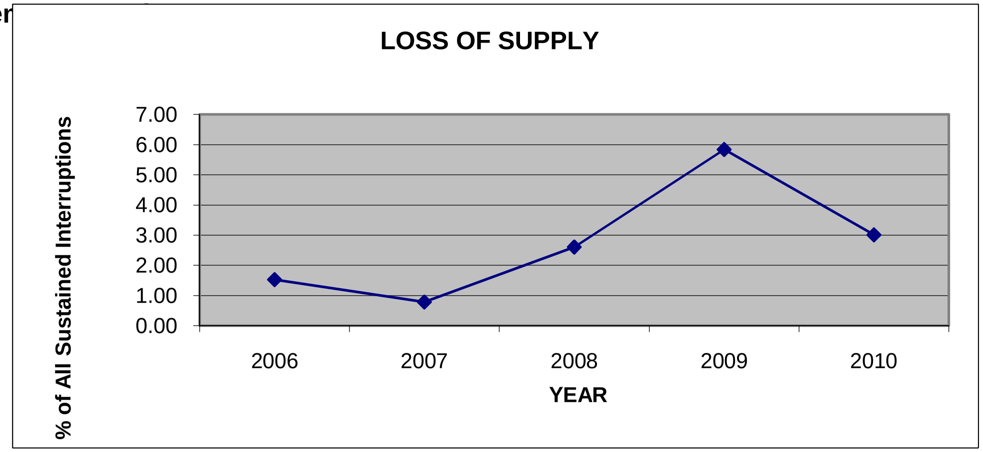


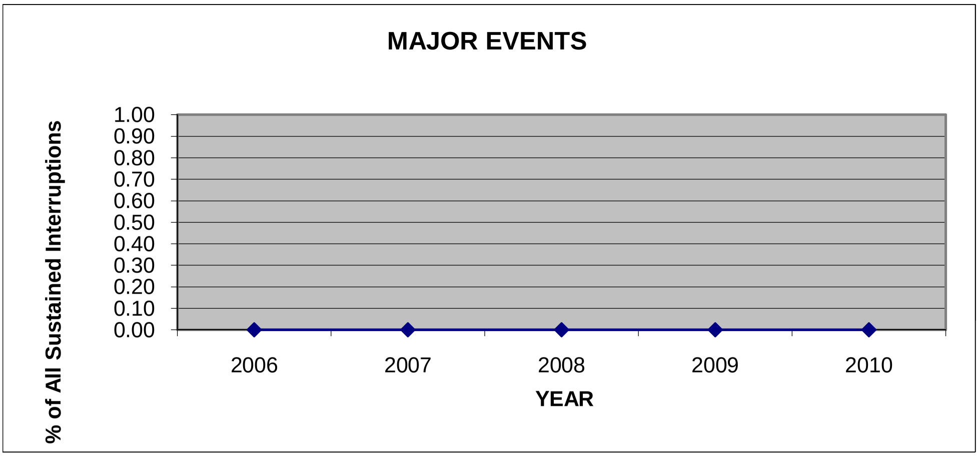


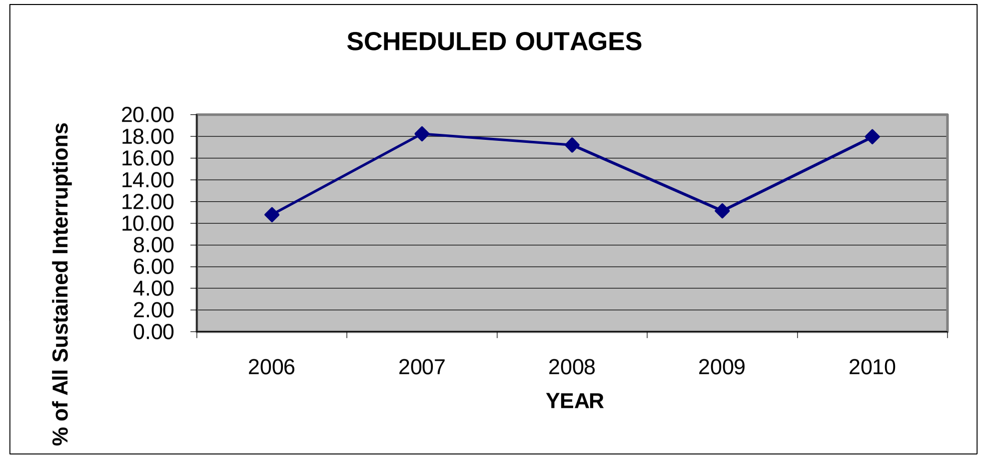


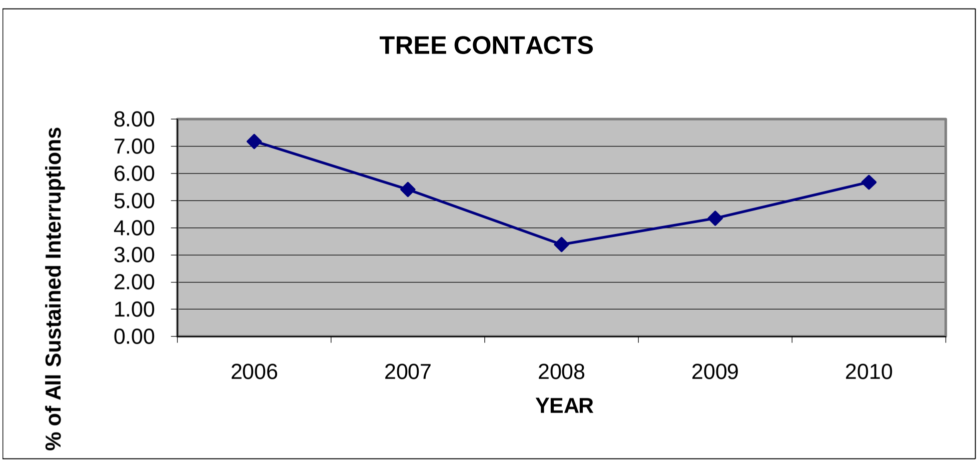
yster


LIGHTNING
% of All Sustained Interruptions
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2006
2007
2008
2009
2010
YEAR


LOSS OF SUPPLY
% of All Sustained Interruptions
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2006
2007
2008
2009
2010
YEAR


MAJOR EVENTS
% of All Sustained Interruptions
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
2006
2007
2008
2009
2010
YEAR


SCHEDULED OUTAGES
% of All Sustained Interruptions
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2006
2007
2008
2009
2010
YEAR


TREE CONTACTS
% of All Sustained Interruptions
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2006
2007
2008
2009
2010
YEAR

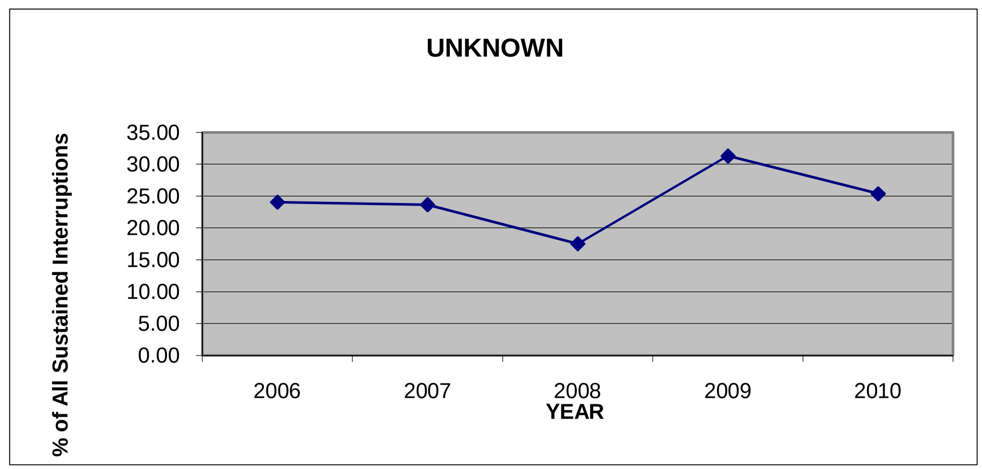
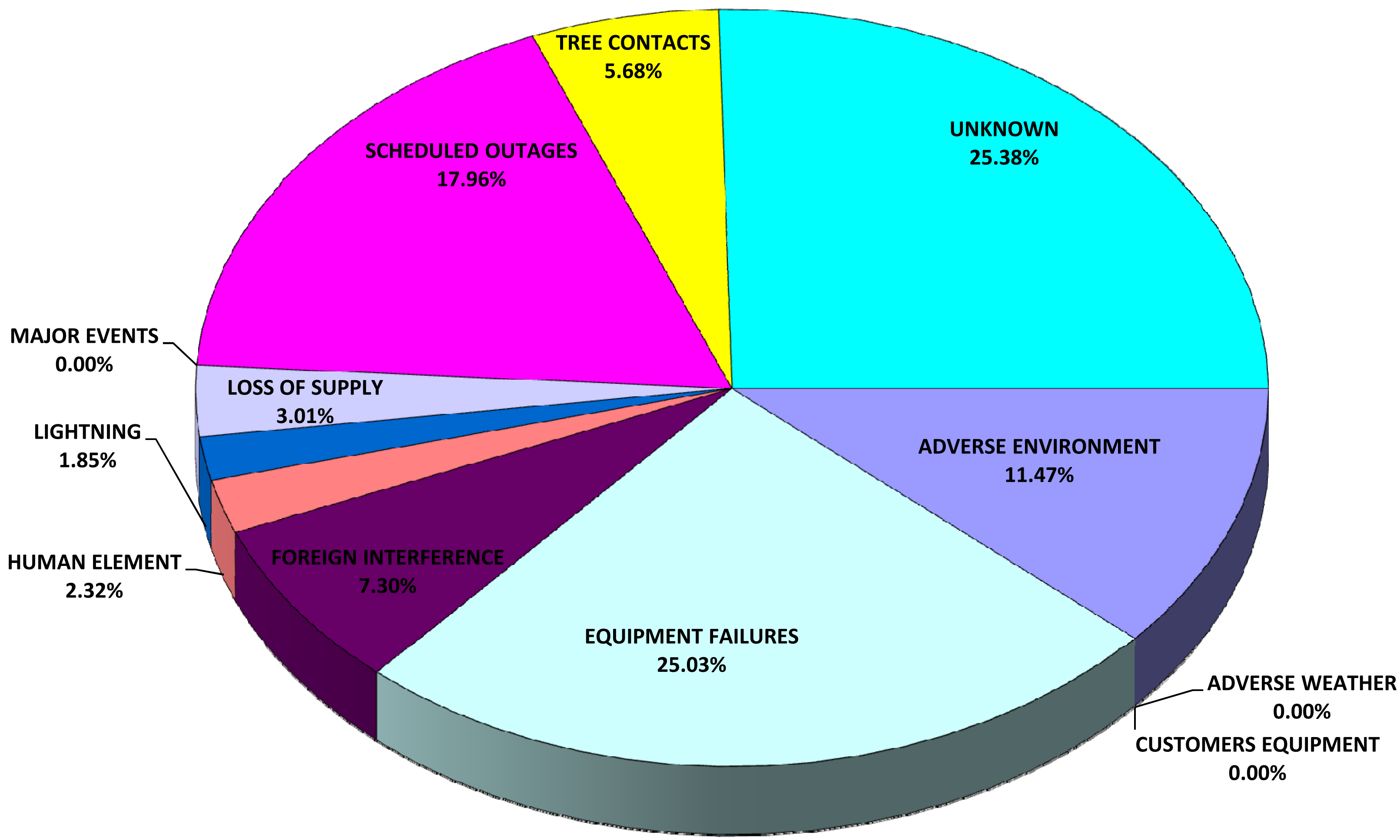

UNKNOWN
% of All Sustained Interruptions
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
2006
2007
2008
2009
2010
YEAR

CHART 4

2010 Causes for Sustained Interruptions



Oregon Circuits Exceeding the Threshold Limit in 2010

TABLE 7

SAIDI VALUES			SAIFI VALUES			$MAIFI_E$ VALUES		
CIRCUIT	**2010**	**THRESHOLD**	**CIRCUIT**	**2010**	**THRESHOLD**	**CIRCUIT**	**2010**	**THRESHOLD**
CARO13	1.75	1.45	ESTN11	7.00	6.00	HFWY11	15.60	14.95
CWVY12	50.35	14.19	LIME12	5.04	4.80	HMDL12	20.03	5.00
HFWY11	21.65	11.83	VALE13	3.58	3.57	HRPR12	23.07	22.95
JNVY12	44.29	28.11				JNTA12	20.00	18.97
LIME12	25.53	12.07				JNVY12	14.00	9.00
OIDA12	4.90	4.57				JNVY31	19.54	10.00
ONTO19	1.67	1.54				LIME11	4.77	4.00
						OBPR11	3.59	2.00
						ONTO24	14.00	7.81
						RKVL11	11.00	3.00
						UNTY11	14.00	13.00
						VALE13	10.37	5.82

Five Years of Line/Trench Miles Data

TABLE 8

OH Line (Pole) Miles

YEAR	MILES
2010	2,114.69
2009	2120.26
2008	2,343.87
2007	2298.29
2006	2,105.77

UG Trench Miles

YEAR	MILES
2010	92.13
2009	92.11
2008	84.36
2007	90.28
2006	85.71

Distribution All Trench Miles

YEAR	MILES
2010	2,206.82
2009	2215.54
2008	2,204.62
2007	2,208.01
2006	2,191.48

Transmission Line (Structure/Pole) Miles *

YEAR	MILES
2010	675.12
2009	667.75
2008	667.59
2007	662.21
2006	661.75

Customer Counts

YEAR	COUNT	OH/UG %
2010	19447	87/13
2009	19,493	87/13
2008	19,487	87/13
2007	19,543	88/12
2006	19,406	88/12

Notes:

* Transmission line miles include some lines that do not directly serve customer load

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES)
AND CHARGES FOR ELECTRIC)
SERVICE TO ITS CUSTOMERS IN THE)
STATE OF OREGON.)
)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

July 29, 2011

DIRECT TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states, including the Public Utility Commission of Oregon ("OPUC" or "the Commission").

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for 20 years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. Exhibit 401 contains a resume presenting the details of my experience and qualifications.

A. Overview.

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

A. The purpose of my testimony is to present to the OPUC my independent evaluation of the fair rate of return on equity ("ROE") for the jurisdictional utility operations of Idaho Power Company ("Idaho Power" or "the Company"). The overall rate of return applied to Idaho Power's 2011 test year rate base is developed in the testimony of Mr. Steven R. Keen.

Q. Please summarize the information and materials you relied on to support the opinions and conclusions contained in your testimony.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the organization, finances, and operations of Idaho Power from my participation in prior proceedings before the OPUC, the Idaho Public Utilities Commission ("IPUC"), and the FERC. In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to the Company and its parent, IDACORP, Inc. ("IDACORP"). I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for Idaho Power's electric utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required rate of return for Idaho Power, and they form the basis of my analyses and conclusions.

Q. What is the practical test of the reasonableness of the ROE used in setting a utility's rates?

A. The ROE compensates investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate the utility's investors; (2) enable the utility to offer a return adequate to attract new capital on reasonable terms; and (3) maintain the utility's financial integrity.

Q. How did you evaluate a fair ROE for Idaho Power?

A. I first reviewed the operations and finances of Idaho Power and the general conditions in the utility industry and the capital markets. With these as a background, I described the conceptual principles underlying investors' required rate of return and then conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF"), the Capital Asset Pricing Model ("CAPM"), an equity risk premium approach based on allowed rates of return, as well as reference to comparable earned rates of return expected for utilities. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and economic requirements for Idaho Power, as well as other factors (e.g., flotation costs) that are properly considered in setting a fair ROE for the Company.

B. <u>Summary of Conclusions</u>.

Q. What are your findings regarding the fair rate of return on equity for Idaho Power?

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[1] Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679 (1923).

[2] Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that Idaho Power be authorized a fair rate of return on equity in the range of a "bare bones" low end of 10.40 percent to a high end (including flotation costs) of 11.55 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Idaho Power's jurisdictional utility operations, my analyses focused on a proxy group of other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, and risk premium methods, as well as the comparable earnings approach, to estimate a fair ROE for Idaho Power;
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the range of 10.4 percent to 11.4 percent, or 10.55 percent to 11.55 percent after incorporating a minimal adjustment to account for the impact of common equity flotation costs;
- Considering the expected upward trend in capital costs and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, it is my opinion that this 10.55 percent to 11.55 percent range bounds a reasonable rate of return on common equity for Idaho Power; and
- As reflected in the testimony of Mr. Keen, Idaho Power is requesting a fair ROE of 10.5 percent to balance customer impact during these challenging economic times with the Company's need to maintain is financial integrity and

access to capital. This 10.5 percent ROE falls at the bottom end of my "bare bones" cost of equity range and, in my professional opinion, represents a reasonable, even if conservative, rate of return on common equity for Idaho Power.

Q. What is your conclusion as to the reasonableness of the Company's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of approximately 51 percent represents a reasonable basis from which to calculate Idaho Power's overall rate of return. This conclusion was based on the following findings:

- Idaho Power's proposed common equity ratio is entirely consistent with the range of capitalizations maintained by the firms in the proxy group of electric utilities at year-end 2010 and based on investors' expectations; and
- My conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks, including the uncertainties posed by exposure to variable hydro conditions, and the pressures of capital investments. Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and Idaho Power's capital structure reflects the Company's ongoing efforts to support its credit standing and maintain access to capital on reasonable terms.

Q. What other evidence did you consider in evaluating your recommendation in this case?

A. My recommendation was reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;
- Because of Idaho Power's reliance on hydroelectric generation, the Company is exposed to relatively greater risks of power cost volatility;

- Providing Idaho Power with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs; and
- Continued support for Idaho Power's financial integrity, including a reasonable ROE, is imperative to ensure that the Company has the capability to maintain an investment grade rating while confronting potential challenges associated with funding infrastructure development necessary to meet the needs of its customers.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to the quantitative analyses that I address later in this testimony, this section briefly reviews the operations and finances of Idaho Power. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair ROE.

A. Idaho Power Company.

Q. Briefly describe Idaho Power.

A. Idaho Power is a wholly-owned subsidiary of IDACORP and is principally engaged in providing integrated retail electric utility service in a 24,000 square mile area in southern Idaho and eastern Oregon. During 2010, Idaho Power's energy deliveries totaled 15.5 million megawatt-hours. Sales to residential customers comprised 37 percent of retail sales, with 28 percent to commercial, 23 percent to industrial end-users, and 12 percent attributable to irrigation pumping. Idaho Power also participates in the wholesale power market and supplies firm wholesale power service under sales contracts. At year-end 2010, Idaho Power had total assets of $4.6 billion, with total revenues amounting to approximately $1.0 billion.

In addition to its thermal baseload and peaking units located in Wyoming, Nevada, Oregon, and Idaho, Idaho Power's existing generating units include 17 hydroelectric generating plants located in southern Idaho and eastern Oregon. The electrical output of these hydro plants, which has a significant impact on total energy costs, is dependent on streamflows. Although Idaho Power estimates that hydroelectric generation is capable of supplying approximately 55 percent of total system requirements under normal conditions, the Company has experienced prolonged periods of persistent below-normal water conditions in the past.

Idaho Power's retail electric operations are subject to the jurisdiction of the OPUC and the IPUC, with the interstate jurisdiction regulated by FERC. Additionally, Idaho Power's hydroelectric facilities are subject to licensing under the Federal Power Act, which is administered by FERC, as well as the Oregon Hydroelectric Act. Relicensing is not automatic under federal law, and in order to successfully complete the process Idaho Power must demonstrate that it has operated its facilities in the public interest, which includes adequately addressing environmental concerns.

Q. How are fluctuations in power costs caused by varying hydro and power market conditions accommodated in Idaho Power's rates?

A. The OPUC has approved two mechanisms that allow Idaho Power to recover its variable power supply expenses: (1) the annual power cost update ("APCU") and (2) the Power Cost Adjustment Mechanism ("PCAM"). Rates resulting from the APCU filing reflect a combined adjustment based on forecasted, normalized, and actual power supply expenses. The PCAM is an annual true-up mechanism that tracks deviations between actual power costs and the power costs forecasted under the APCU.

Positive deviations between the Company's actual calendar year power costs and the APCU calculations (i.e., actual expenses are greater than amounts recovered) are reduced by the dollar equivalent of a 250 basis point reduction to the then-authorized ROE. Once reduced, 90 percent of the remaining excess power supply cost amount is deferred for subsequent recovery in rates. Negative deviations (i.e., actual expenses lower than amounts recovered) are reduced by the dollar equivalent of a 125 basis point reduction to the Company's then-authorized ROE. Once reduced, 90 percent of the remaining amount is deferred for possible refunds to customers.

Before any reductions or refunds are deferred under the PCAM, the Commission applies an earnings test. If earnings during the year that Idaho Power incurred the excess net variable power costs are within 100 basis points of the Company's authorized rate of return, no true-up amounts are added to the PCAM balancing account. If the Company's earnings are 100 basis points or more below its authorized ROE, the Company is allowed to add 90 percent of the eligible amounts to the PCAM balancing account, up to an earnings level that is 100 basis points less than the Company's authorized ROE. If earnings are more than 100 basis points above the Company's authorized ROE, the Company can include 90 percent of the eligible amounts as a credit to the balancing account, down to an earnings level that is 100 basis points above its authorized ROE.

Q. What credit ratings have been assigned to Idaho Power?

A. Idaho Power has been assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P") and an issuer rating of "Baa1" from Moody's Investor Services, Inc. ("Moody's").

B. <u>Operating Risks</u>.

Q. How have investors' risk perceptions for the utility industry evolved?

A. Implementation of structural change, along with other factors impacting the economy and the industry, has caused investors to rethink their assessment of the relative risks associated with utilities. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. In December 2009, S&P observed with respect to the industry's future that:

> Looming costs associated with environmental compliance, slack demand caused by economic weakness, the potential for permanent demand destruction caused by changes in consumer behavior and closing of manufacturing facilities, and numerous regulatory filings seeking recovery of costs are some of the significant challenges the industry has to deal with.[3]

Similarly, Moody's noted:

> [A] sustained period of sluggish economic growth, characterized by high unemployment, could stress the sector's recovery prospects, financial performance, and credit ratings. The quality of the sector's cash flows are already showing signs of decline, partly because of higher operating costs and investments.[4]

More recently, Moody's concluded, "we also see the sector's overall business and operating risks increasing."[5]

Q. How does Idaho Power's generating resource mix affect investors' risk perceptions?

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[3] Standard & Poor's Corporation, "U.S. Regulated Electric Utilities Head into 2010 With Familiar Concerns," *RatingsDirect* (Dec. 28, 2009).

[4] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[5] Moody's Investors Service, "Regulation Provides Stability as Risks Mount," *Industry Outlook* (Jan. 19, 2011).

A. Because approximately one-half of Idaho Power's total energy requirements are provided by hydroelectric facilities, the Company is exposed to a level of uncertainty not faced by most utilities. While hydropower confers advantages in terms of fuel cost savings and diversity, reduced hydroelectric generation due to below-average water conditions forces Idaho Power to rely more heavily on wholesale power markets or more costly thermal generating capacity to meet its resource needs. As S&P has observed:

> A reduction in hydro generation typically increases an electric utility's costs by requiring it to buy replacement power or run more expensive generation to serve customer loads. Low hydro generation can also reduce utilities' opportunity to make off-system sales. At the same time, low hydro years increase regional wholesale power prices, creating potentially a double impact – companies have to buy more power than under normal conditions, paying higher prices.[6]

Uncertainties over water conditions are a persistent operational risk associated with Idaho Power. Investors recognize that volatile energy markets, unpredictable stream flows, and Idaho Power's reliance on wholesale purchases to meet a significant portion of its resource needs can expose the Company to the risk of reduced cash flows and unrecovered power supply costs. S&P noted that Idaho Power, along with Avista Corporation, "face the most substantial risks despite their PCAs and cost-update mechanisms,"[7] and recently concluded that Idaho Power's generation mix "exposes the company to substantial replacement power risk in the event of low water flows that lead to reduced generation."[8] Similarly, Moody's

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[6] Standard & Poor's Corporation, "Pacific Northwest Hydrology and Its Impact on Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

[7] *Id*.

[8] Standard & Poor's Corporation, "Summary: Idaho Power Co.," *RatingsDirect* (Nov. 24, 2010).

observed that Idaho Power "has a high dependency . . . on hydro resources making it vulnerable to drought conditions."[9] In addition to weather-related fluctuations in water flows, Idaho Power is also exposed to uncertainties regarding water rights and the administration of those rights.

Q. Is the potential for energy market volatility an ongoing concern for investors?

A. Yes. In recent years, utilities and their customers have had to contend with dramatic fluctuations in fuel costs due to ongoing price volatility in the spot markets, and investors recognize the potential for further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. The investment community also recognizes that financial performance can be negatively impacted when low wholesale prices impair revenues from surplus energy sales, as has been the case recently in the Pacific Northwest.[10]

While current expectations for significantly lower wholesale power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. For example, heightened uncertainties in the Middle East have led to sharp increases in petroleum prices, and the potential ramifications of the Japanese nuclear crisis on the future cost and availability of nuclear generation in the U.S. have not been lost on investors. S&P observed that "short-term price volatility from numerous possibilities . . . is always possible,"[11] while Moody's recognized that "the inherent volatility of

[9] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (Mar. 9, 2011).

[10] *See, e.g.,* Standard & Poor's Corporation, "Summary: Energy Northwest, Washington Bonneville Power Administration, Oregon; Wholesale Electric," *RatingsDirect* (Apr. 27, 2011).

[11] Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).

commodity costs comprises one of the most significant risk factors to the industry,"[12] and concluded, "This view, that commodity prices remain low, could easily be proved incorrect, due to the evidence of historical volatility."[13]

Q. Do the APCU and PCAM completely shield Idaho Power from exposure to fluctuations in power supply costs?

A. No. The investment community views the Company's ability to periodically adjust retail rates to accommodate fluctuations in fuel costs as an important source of support for Idaho Power's financial integrity. Nevertheless, they also recognize that there can still be a lag between the time Idaho Power actually incurs the expenditure and when it is recovered from ratepayers, during which the Company does not earn a return on its investment. This lag can impinge on the utility's financial strength through reduced liquidity and higher borrowings. As a result, the Company is not insulated from the potential need to finance deferred fuel costs.[14] Moreover, under the earnings test applied by the OPUC, Idaho Power may be denied recovery altogether of a portion it its power costs, and under the sharing mechanism contained in the PCAM, deferrals are capped at 90 percent of eligible amounts. As a result, despite the significant investment of resources to manage fuel procurement, investors are aware that the best that Idaho Power can do is to recover something less than its actual costs during times of rising fuel costs. Finally, Idaho Power faces the possibility that there will be disallowances for imprudence in its fuel procurement.

Similarly, as discussed in the testimony of Mr. Keen, Idaho Power devotes

[12] Moody's Investors Service, "Credit Opinion: Avista Corp.," *Global Research* (Mar. 17, 2011).

[13] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[14] S&P has noted that the Company's financial metrics have been negatively impacted in the past as a result of power cost deferrals. Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (Feb. 1, 2008).

considerable resources to the administration of power purchase contracts ("PPAs"), which provide no opportunity to earn a return for shareholders.

Q. What other financial pressures impact investors' risk assessment of Idaho Power?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[15] As Moody's observed:

> [W]e also see the sector's overall business risk and operating risks increasing, owing primarily to rising costs associated with upgrading and expanding the nation's trillion dollar electric infrastructure.[16]

Similarly, S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[17] Providing the infrastructure necessary to meet the energy needs of customers imposes additional financial responsibilities on Idaho Power.

Q. Does Idaho Power anticipate the need to access the capital markets going forward?

A. Most definitely. Idaho Power will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission,

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[15] Standard & Poor's Corporation, "Industry Economic and Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).

[16] Moody's Investors Service, "Regulation Provides Stability as Risks Mount," *Industry Outlook* (Jan. 19, 2011).

[17] Standard & Poor's Corporation, "Industry Economic and Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).

and distribution facilities. Idaho Power is in a period of significant infrastructure development and has several major projects in development, including construction of the 300 megawatt Langley Gulch power plant, which is expected to achieve commercial operation in the summer of 2012.

As Moody's noted, "IPC's capital expenditures are expected to range from $775 - $805 million over the next three years."[18] Investors are aware of the challenges posed by rising costs and burdensome capital expenditure requirements, especially in light of ongoing capital market and economic uncertainties. Support for Idaho Power's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Q. What other considerations affect investors' evaluation of Idaho Power?

A. Utilities are confronting increased environmental pressures that create significant uncertainties and could impose substantial costs. Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities."[19] While the momentum for carbon emissions legislation has slowed, expectations for eventual regulations continue to pose uncertainty. Fitch recently concluded, "Prospects of costly environmental regulations will create uncertainty for investors in the electricity business in 2011."[20] Moody's observed that "increasingly stringent environmental mandates" are a key risk confronting Idaho Power.[21]

[18] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (Mar. 9, 2011).

[19] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

[20] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010).

[21] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (Mar. 9, 2011).

Q. Do investors consider Idaho Power's relative size in their assessment of the Company's risks and prospects?

A. Yes. A firm's relative size has important implications for investors in their evaluation of alternative investments, and it is well established that smaller firms are more risky than larger firms. With a market capitalization of approximately $1.8 billion, Idaho Power is one of the smallest publicly traded electric utilities followed by The Value Line Investment Survey ("Value Line"), which have an average capitalization of approximately $7.3 billion.[22]

The magnitude of the size disparity between Idaho Power and other firms in the utility industry has important practical implications with respect to the risks faced by investors. All else being equal, it is well accepted that smaller firms are more risky than their larger counterparts, due in part to their relative lack of diversification and lower financial resiliency.[23] These greater risks imply a higher required rate of return, and there is ample empirical evidence that investors in smaller firms realize higher rates of return than in larger firms.[24] Common sense and accepted financial doctrine hold that investors require higher returns from smaller companies, and unless that compensation is provided in the rate of return allowed for a utility, the legal tests embodied in the *Hope* and *Bluefield* cases cannot be met.

C. Impact of Capital Market Conditions.

Q. What are the implications of recent capital market conditions?

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[22] www.valueline.com (Retrieved Mar. 25, 2011).

[23] It is well established in the financial literature that smaller firms are more risky than larger firms. *See, e.g.*, Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Stock Returns," *The Journal of Finance* (June 1992); George E. Pinches, J. Clay Singleton, and Ali Jahankhani, "Fixed Coverage as a Determinant of Electric Utility Bond Ratings," *Financial Management* (Summer 1978).

[24] *See*, *e.g.*, Rolf W. Banz, "The Relationship Between Return and Market Value of Common Stocks," *Journal of Financial Economics* (September 1981) at 16.

A. The deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009, led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of June 2011, the Dow Jones Utility Average stock index remained approximately 17 percent below the previous high reached in May 2008. The prolonged sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry is not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute noted in a letter to congressional representatives in September 2008 as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[25]

While conditions have improved significantly since the depths of the crisis, investors have nonetheless had to confront ongoing fluctuations in share prices and stress in the credit markets. As the Wall Street Journal noted in February 2010:

> Stocks pulled out of a 167-point hole with a late rally Friday, capping a wild week reminiscent of the most volatile days of the credit crisis.
>
> * * *

[25] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

> It was a return to the unusual relationships, or correlations, seen at major flash points over the past two years when investors fled risky assets and jumped into safe havens. This market behavior, which has reasserted itself repeatedly since the financial crisis began, suggests that investment decisions are still being driven more by government support and liquidity concerns than market fundamentals.[26]

In response to renewed capital market uncertainties initiated by unrest in the Middle East, the natural disaster in Japan, ongoing concerns over the European sovereign debt crisis, and questions over the sustainability of economic growth, investors have repeatedly fled to the safety of U.S. Treasury bonds, and stock prices have experienced renewed volatility.[27] The dramatic rise in the price of gold and other commodities also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. With respect to utilities, Fitch observed that, "the outlook for the sector would be adversely affected by significantly higher inflation and interest rates."[28] Moody's recently concluded:

> Over the past few months, we have been reminded that global financial markets, which are still receiving extraordinary intervention benefits by sovereign governments, are exposed to turmoil. Access to the capital markets could therefore become intermittent, even for safer, more defensive sectors like the power industry.[29]

[26] Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010).

[27] The Wall Street Journal recently reported that the Dow Jones Industrial Average experienced its largest drop since August 2010, which marked the fourth triple-digit move in less than two weeks. Tom Lauricella and Jonathan Cheng, "Dow Below 12000 on Mideast Worries – Troubles in Europe and China Add to Jitters," *Wall Street Journal* C1 (March. 11, 2011).

[28] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010).

[29] Moody's Investors Service, "Regulation Provides Stability as Risks Mount," *Industry Outlook* (Jan. 19, 2011).

Uncertainties surrounding economic and capital market conditions heighten the risks faced by utilities, which, as described earlier, face a variety of operating and financial challenges.

Q. How do interest rates on long-term bonds compare with those projected for the next few years?

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from Value Line, IHS Global Insight, Blue Chip Financial Forecasts (“Blue Chip”), and the Energy Information Administration (“EIA”), which is a statistical agency of the U.S. Department of Energy.

TABLE WEA-1
INTEREST RATE TRENDS

	Current (a)	2012	2013	2014	2015
30-Yr. Treasury					
Value Line (b)	4.5%	4.9%	5.2%	5.5%	6.0%
IHS Global Insight (c)	4.5%	4.7%	5.0%	5.1%	6.0%
Blue Chip (d)	4.5%	4.8%	5.2%	5.4%	5.5%
AAA Corporate					
Value Line (b)	5.1%	5.6%	6.0%	6.3%	6.5%
IHS Global Insight (c)	5.1%	5.2%	6.0%	6.2%	6.8%
Blue Chip (d)	5.1%	5.4%	5.8%	6.1%	6.3%
S&P (e)	5.1%	6.1%	5.7%	5.9%	6.3%
AA Utility					
IHS Global Insight (c)	5.3%	5.4%	6.3%	6.4%	7.2%
EIA (f)	5.3%	5.5%	6.4%	7.0%	7.4%

(a) Based on monthly average bond yields for the six-month period Nov. 2010 - Apr. 2011 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases/h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 25, 2011).
(c) IHS Global Insight, *U.S. Economic Outlook* at 19 (Feb. 2011).
(d) *Blue Chip Financial Forecasts,* Vol. 29, No. 12 (Dec. 1, 2010).
(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Pouring Water On Troubled Oil," *RatingsDirect* (Mar. 8, 2011).
(f) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2012-2015 time frame than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. What do these events imply with respect to the ROE for Idaho Power?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it did, or that corporate bond yields would fluctuate as dramatically as they have. While conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. The fact remains that the electric utility industry requires significant new capital investment. Given the importance of reliable utility service, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case. Similarly, the Company's capital structure must also preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF, CAPM, and risk premium analyses conducted to estimate the cost of equity for benchmark groups of comparable risk firms and evaluate comparable earned rates of return expected for utilities. Finally, I examine other factors (e.g., flotation costs) that are properly considered in evaluating a fair ROE.

A. Overview.

Q. What role does the return on common equity play in a utility's rates?

A. The return on common equity is the cost of attracting and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q. What fundamental economic principle underlies any evaluation of investors' required return on equity?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk-averse. In capital markets where relatively risk-free assets are available (e.g., U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and

RP_i = Risk premium required to hold risky asset i.

Thus, the required rate of return for a particular asset at any point in time is a function of: (1) the yield on risk-free assets and (2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets–including common stock–required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is therefore the least risky. Following bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What does the above discussion imply with respect to estimating the cost of equity for a utility?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Did you rely on a single method to estimate the cost of equity for Idaho Power?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. Similarly, the OPUC has also considered the results of alternative methods in establishing allowed ROEs for utilities under its jurisdiction. Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity, and considered the results of the risk premium and comparable earnings approaches. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

B. Comparable Risk Proxy Groups.

Q. How did you implement these quantitative methods to estimate the cost of common equity for Idaho Power?

A. Application of the DCF model and other quantitative methods to estimate the cost of equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of equity can only be estimated. As a result, applying quantitative models using observable market data produces only an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk comparable.

Q. What specific proxy group did you rely on for your analysis?

A. In order to reflect the risks and prospects associated with Idaho Power's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies included by Value Line in its Electric Utilities Industry groups with: (1) S&P corporate credit ratings of "BBB-" to "BBB+"; (2) a Value Line Safety Rank of "2" or "3"; and (3) a Value Line Financial Strength Rating of "B+" to "B++."[30] I refer to this group as the "Utility Proxy Group."

Q. What other proxy group did you consider in evaluating a fair ROE for Idaho Power?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair ROE is relative risk, not the particular business activity or degree of regulation. With regulation

[30] In addition, I excluded three utilities (FirstEnergy Corp., Northeast Utilities, and Progress Energy, Inc.) that otherwise would have been in the proxy group, but are not appropriate for inclusion because they are currently involved in a major merger or acquisition.

taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a select group of low-risk risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group."

Q. What criteria did you apply to develop the Non-Utility Proxy Group?

A. My comparable risk proxy group of non-utility firms was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or greater; (4) have a beta of 0.85 or less; and (5) have investment grade credit ratings from S&P.

Q. Do these criteria provide objective evidence to evaluate investors' risk perceptions?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (e.g., "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Although the credit rating agencies are not immune to criticism, their rankings and analyses are widely cited in the investment community and referenced by investors.[31] Investment restrictions tied to credit ratings continue to influence

[31] While the ratings agencies were faulted during the financial crisis for failing to adequately assess the risk associated with structured finance products, investors continue to regard corporate credit ratings as a reliable guide to investment risks.

capital flows, and credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

Q. How do the overall risks of your proxy groups compare with Idaho Power?

A. Table WEA-2 below compares the Utility Proxy Group with the Non-Utility Proxy Group and Idaho Power across four key indicators of investment risk. Because the Company does not have publicly traded common stock, the Value Line risk measures shown reflect those published for the Company's parent, IDACORP.

TABLE WEA-2
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
	Credit Rating	**Safety Rank**	**Financial Strength**	**Beta**
Utility Group	BBB	3	B+	0.76
Non-Utility Group	A	1	A+	0.71
Idaho Power	BBB	3	B+	0.70

Q. Do these comparisons indicate that investors would view the firms in your proxy groups as risk-comparable to Idaho Power?

A. Yes. Considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position and exposure to firm-specific factors, indicates that investors would likely conclude that the overall investment risks for Idaho Power are generally comparable to those of the firms in the Utility Proxy Group.

With respect to the Non-Utility Proxy Group, its average credit ratings, Safety Rank, and Financial Strength Rating suggest less risk than for Idaho Power, with its 0.71 average beta indicating essentially identical risk. While the impact of differences in regulation is reflected in objective risk measures, my analyses conservatively focus on a lower-risk group of non-utility firms.

C. <u>Discounted Cash Flow Analyses</u>.

Q. What is the economic basis underlying the DCF model?

A. The DCF model attempts to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of equity.

Q. What form of the DCF model is customarily used to estimate the cost of equity in rate cases?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form as shown below:[32]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in coming year;
k_e = Cost of equity;
g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: (1) dividend yield (D_1/P_0) and (2) growth "g."

[32] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings, a stable dividend payout ratio, the discount rate exceeds the growth rate, a constant growth rate for book value and price, a constant earned rate of return on book value, no sales of stock at a price above or below book value, a constant price-earnings ratio, a constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve), and all of the above extend to infinity.

In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. What form of the DCF model did you use?

A. I applied the constant growth DCF model to estimate the cost of equity for Idaho Power, which is the form of the model most commonly relied on to establish the cost of equity for traditional regulated utilities and the method most often referenced by regulators.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations "g" for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. How was the dividend yield for the Utility Proxy Group determined?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Proxy Group are presented on Exhibit 402. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 2.0 percent to 5.9 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "g," for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "g" that matters in applying the DCF model is the value that investors expect.

Q. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. Past trends in earnings, dividends, and book value are representative of investors' expectations for the future only to the extent that the historical conditions giving rise to these growth rates are expected to continue. That is clearly not the case for electric utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term growth for the electric utility industry or the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of electric utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[33] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the electric utility industry have trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. 'Healthy earnings equal healthy investment benefits' seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[34]

Value Line's near-term projections and its Timeliness Rank,[35] which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

[33] For example, the payout ratio for electric utilities fell from approximately 80 percent historically to on the order of 60 percent. The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 4, 2011 at 2237).

[34] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview," p. 1 (Dec. 4, 1996).

[35] The Timeliness Rank presents Value Line's assessment of relative price performance during the next six to 12 months based on a five point scale.

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[36]

The fact that investment advisory services focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[37] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only three ranked dividends first while 276 ranked it last. The article concluded that "Earnings and cash flow are considered far more important than book value and dividends."[38]

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[39]

Q. Do the growth rate projections of security analysts consider historical trends?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful

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[36] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

[37] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory," *Financial Analysts Journal* (July/August 1999).

[38] *Id.* at 88.

[39] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.

information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. What are security analysts currently projecting in the way of growth for the firms in the Utility Proxy Group?

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on Exhibit 402.[40]

Q. Some argue that analysts' assessments of growth rates are biased. Do you believe these projections are inappropriate for estimating investors' required return using the DCF model?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory

[40] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts–whether pessimistic or optimistic–is similarly irrelevant if investors share the analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[41]

Q. How else are investors' expectations of future long-term growth prospects often estimated for use in the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in

[41] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.,* at 298 (2006).

book value. Despite the fact that these conditions are seldom, if ever, met in the real world, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Utility Proxy Group?

A. The sustainable, "br+sv" growth rates for each firm in the Utility Proxy Group are summarized on Exhibit 402, with the underlying details being presented on Exhibit 403. For each firm, the expected retention ratio "b" was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return "r" was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock "s" was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate "v" was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What cost of equity estimates were implied for the Utility Proxy Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of equity estimates are shown on Exhibit 402.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate cost of equity estimates that are extreme low or high outliers?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. How did you evaluate DCF estimates at the low end of the range?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF results must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. What does this test of logic imply with respect to the DCF results for the Utility Proxy Group?

A. As noted earlier, the average S&P corporate credit rating for the Utility proxy Group is "BBB," the same as for Idaho Power. Companies rated "BBB-," "BBB," and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.0 percent in April 2011.[42] It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's 'A' grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[43]

Similarly, in its August 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

[42] Moody's Investors Service, www.credittrends.com.

[43] *Southern California Edison Company*, 92 FERC ¶ 61,070 at p. 22 (2000).

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[44]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[45]

The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[46] and in its April 15, 2010, decision in *SoCal Edison*, FERC affirmed that "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[47]

Q. What else should be considered in evaluating DCF estimates at the low end of the range?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 7.15 percent over the period 2012-2015.

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[44] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).

[45] *Id.*

[46] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).

[47] *Southern California Edison Co.,* 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

TABLE WEA-3
IMPLIED BBB BOND YIELD

	2012-15
Projected AA Utility Yield	
IHS Global Insight (a)	6.33%
EIA (b)	6.58%
Average	6.45%
Current BBB - AA Yield Spread (c)	0.70%
Implied Triple-B Utility Yield	**7.15%**

(a) IHS Global Insight, *U.S. Economic Outlook* at 19 (Feb. 2011).
(b) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).
(c) Based on monthly average bond yields for the six-month period Nov. 2010 - Apr. 2011.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip, which projects that yields on corporate bonds will climb more than 100 basis points through the period 2012-2016.[48]

Q. What does this test of logic imply with respect to the DCF results for the Utility Proxy Group?

A. As shown on Exhibit 402, eight low-end DCF estimates ranged from 2.4 percent to 7.0 percent. Three of these values were below current utility bond yields, with cost of equity estimates of 7.0 percent or below being less than the yield on triple-B utility bonds expected during the period 2012-2015. In light of the risk-return tradeoff principle and the test applied in *SoCal Edison*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and the upward trend expected for utility bond yields, these

[48] *Blue Chip Financial Forecasts*, Vol. 29, No. 12 (Dec. 1, 2010) & Vol. 30, No. 3 (Mar. 1, 2011).

values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. Do you also recommend excluding estimates at the high end of the range of DCF results?

A. Yes. The upper end of the cost of common equity range produced by the DCF analysis presented in Exhibit 402 was set by five cost of equity estimates ranging from 17.0 percent to 23.3 percent. When compared with the balance of the remaining estimates, these values are clearly implausible and should be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[49]

Q. What cost of equity is implied by your DCF results for the Utility Proxy Group?

A. As shown on Exhibit 402 and summarized in Table WEA-4 below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates.

TABLE WEA-4
DCF RESULTS – UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.4%
IBES	10.5%
Zacks	10.4%
br+sv	9.1%

Q. What were the results of your DCF analysis for the Non-Utility Proxy Group?

A. I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group. The results of my DCF analysis for the

[49] *See*, *e.g.*, *ISO New England*, *Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

Non-Utility Proxy Group are presented in Exhibit 404, with the sustainable, "br+sv" growth rates being developed on Exhibit 405. As shown on Exhibit 404 and summarized in Table WEA-5 below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates on the order of at least 12 percent.

TABLE WEA-5
DCF RESULTS – NON-UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.9%
IBES	12.4%
Zacks	12.5%
br+sv	12.1%

As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles and required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

D. <u>Capital Asset Pricing Model</u>.

Q. Please describe the CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity both among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
Rm = expected return on the market portfolio; and
Bj = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking historical data.

Q. How did you apply the CAPM to estimate the cost of equity?

A. Application of the CAPM to the Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on page 1 of Exhibit 406. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500 Composite Index.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-years' growth using the rate discussed subsequently (1 + g) to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the consensus earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 354 individual firms, current estimates imply an average growth rate over the next five years of 10.5 percent. Combining this average growth rate with a year-ahead dividend yield of 2.3 percent results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.8 percent. Subtracting a 4.5 percent risk-free rate based on the average yield on 30-year Treasury bonds produced a market equity risk premium of 8.3 percent.

Q. What was the source of the beta values you used to apply the CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors . . . . Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[50]

Q. What else should be considered in applying the CAPM?

A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[51]

Because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors'

[50] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

[51] *Morningstar*, "Ibbotson SBBI 2011 Valuation Yearbook," at p. 83 (footnote omitted).

required rates of return that are related to firm size are not fully captured by beta. To account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[52] Accordingly, my CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups.

Q. What cost of equity estimate was indicated for the Utility Proxy Group based on this forward-looking application of the CAPM?

A. The average market capitalization of the Utility Proxy Group is $5.3 billion. Based on data from *Morningstar*, this means that the theoretical CAPM cost of equity estimate must be increased by 101 basis points to account for the industry group's relative size. As shown on Exhibit 406, adjusting the theoretical CAPM result to incorporate this size adjustment results in an average indicated cost of common equity of 11.8 percent.

Q. What cost of common equity was indicated for the Non-Utility Proxy Group based on this forward-looking application of the CAPM?

A. As shown on page 2 of Exhibit 406, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.0 percent.

Q. Is it appropriate to consider anticipated capital market changes in applying the CAPM?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. As a result, current

[52] *Id.* at Table C-1.

bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight, and Blue Chip.

Q. What cost of equity was produced by the CAPM after incorporating forecasted bond yields?

A. As shown on page 1 of Exhibit 407, incorporating a forecasted yield for 2012-2015 implied a cost of equity of approximately 12.0 percent for the Utility Proxy Group, or 10.2 percent for the group of non-utility firms (page 2 of Exhibit 407).

Q. Should the CAPM approach be applied using historical rates of return?

A. No. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely than it is today. This incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.[53]

E. <u>Risk Premium Approach</u>.

Q. Briefly describe the risk premium method.

A. The risk premium method of estimating investors' required rate of return extends to common stocks the risk-return tradeoff observed with bonds. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. How did you implement the risk premium method?

A. I based my estimates of equity risk premiums for electric utilities on surveys of previously authorized rates of return on common equity. Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such returns should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs.

[53] FERC has previously rejected CAPM methodologies based on historical data because whatever historical relationships existed between debt and equity securities may no longer hold. *See Orange & Rockland Utils., Inc.,* 40 F.E.R.C. P63,053, at pp. 65,208 -09 (1987), aff'd, Opinion No. 314, 44 F.E.R.C. P61,253 at 65,208.

Thus, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. How did you implement the risk premium approach using surveys of allowed rates of return?

A. Surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit 408, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2010. Over this 37-year period, these equity risk premiums for electric utilities averaged 3.36 percent, and the yield on public utility bonds averaged 9.01 percent.

Q. Are there any capital market relationships that must be considered when implementing the risk premium method?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow; conversely, when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1 percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated.

Finally, it is important to recognize that the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing electric utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's electric power industry.

Q. What cost of equity is implied by surveys of allowed rates of return on equity?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 3 of Exhibit 408, the equity risk premium for electric utilities increased approximately 41 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit 408, with the yield on average public utility bonds in April 2011 being 5.62 percent, this implied a current equity risk premium of 4.75 percent for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 5.98 percent produces a current cost of equity of approximately 10.7 percent.

Q. What cost of equity was produced by the risk premium approach after incorporating forecasted bond yields?

A. As shown on page 2 of Exhibit 408, incorporating a forecasted yield for 2012-2015 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.21 percent for electric utilities. Adding this equity risk premium to the average implied yield on triple-B public utility bonds for 2012-2015 of 7.15 percent resulted in an implied cost of equity of approximately 11.4 percent.

F. <u>Comparable Earnings Approach</u>.

Q. What other benchmarks did you develop to evaluate the ROE for Idaho Power?

A. As I noted earlier, I also evaluated the ROE by reference to expected rates of return for electric utilities. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This approach is consistent with the economic underpinnings for a fair rate of return, as reflected in the comparable earnings test established by the Supreme Court in *Hope* and *Bluefield.* Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What economic premise underlies the comparable earnings approach?

A. The simple but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents it from earning its opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation.

Q. How is the comparison of opportunity costs typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (e.g., Value Line). Because these expected returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison. My application of the expected earnings approach was focused exclusively on forward-looking projections, not historical data.

Moreover, regulators do not set the returns that investors earn in the capital markets–they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the comparable earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. What rates of return on equity are indicated for electric utilities based on the comparable earnings approach?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5 percent over its forecast horizon.[54] Meanwhile, for the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit 409. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit 403. As shown on Exhibit 409, Value Line's projections for the Utility Proxy Group suggest an average ROE of 10.4 percent after eliminating outliers.

[54] The Value Line Investment Survey at 901 (Mar. 25, 2011).

G. Flotation Costs.

Q. What other considerations are relevant in determining the ROE for Idaho Power?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds that a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Similarly, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of common equity being the most logical mechanism.

Q. What is the magnitude of the adjustment to the "bare bones" cost of common equity to account for issuance costs?

A. While there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *New Regulatory Finance* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[55]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6 percent.[56]

Issuance costs are a legitimate consideration in setting the ROE for a utility, and applying these expense percentages to a representative dividend yield for a utility of 4.5 percent implies a flotation cost adjustment on the order of 15 to 45 basis points.

IV. RETURN ON EQUITY FOR IDAHO POWER COMPANY

Q. What is the purpose of this section?

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[55] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

[56] Application of Yankee Gas Services Company for a Rate Increase, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6 percent.

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for Idaho Power, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of Idaho Power's requested capital structure.

A. <u>Implications for Financial Integrity</u>.

Q. Why is it important to allow Idaho Power an adequate authorized ROE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While Idaho Power remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with capital expenditure requirements, uncertain economic and financial market conditions, future environmental compliance costs, and the potential for continued energy price volatility. As discussed earlier, Idaho Power faces a number of potential challenges that might require the relatively swift commitment of significant capital resources in order to maintain the high level of service to which customers have become accustomed.

Investors understand how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered firsthand how difficult and complex it can be to remedy the situation after the fact. While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on Idaho Power. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing Idaho Power an adequate return on its investment.

Q. What role does regulation play in ensuring Idaho Power's access to capital?

A. The major rating agencies have warned investors of the exposure to uncertainties associated with political and regulatory developments. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Fitch noted that a weak economic backdrop "could result in political push-back to rate increase requests."[57] Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects."[58] S&P has also emphasized the need for regulatory support, concluding "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[59] Similarly, Moody's concluded:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[60]

Moody's concluded that political risks associated with "growing consumer intolerance for steadily increasing rates" was a key longer-term challenge for utilities

[57] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

[58] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[59] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

[60] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).

that would be intensified by prolonged unemployment.[61] With respect to Idaho Power specifically, the major bond rating agencies have noted the importance of constructive regulatory decisions in mitigating financial pressures, while observing that waning support would likely lead to a deterioration in the Company's credit standing.[62]

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. While providing an ROE that is sufficient to maintain Idaho Power's ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Customers and the service area economy enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service.

B. Capital Structure.

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoints, a higher debt ratio means that there are

[61] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

[62] *See, e.g.,* Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (Mar. 9, 2011).

proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio is implicit in Idaho Power's requested capital structure?

A. Idaho Power's capital structure is presented in the testimony of Mr. Keen. As summarized in his testimony, the common equity ratio used to compute Idaho Power's overall rate of return was approximately 51 percent in this filing.

Q. What was the average capitalization maintained by the Utility Proxy Group?

A. As shown on Exhibit 410, for the firms in the Utility Proxy Group, common equity ratios at December 31, 2010, ranged from 25.3 percent to 63.8 percent and averaged 46.4 percent.

Q. What capitalization is representative for the proxy group of utilities going forward?

A. As shown on Exhibit 410, Value Line expects an average common equity ratio for the proxy group of utilities of 48.9 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 29.0 percent to 67.5 percent.

Q. What implication do the uncertainties facing the utility industry have for the capital structures maintained by electric utilities?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, changing environmental mandates, uncertainties over accommodating economic and financial market uncertainties, and ongoing regulatory risks. Taken together, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital under reasonable terms that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has repeatedly warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[63] More recently, Moody's concluded:

> From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative ratings actions.[64]

Similarly, S&P noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[65] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[66] This is especially the case for electric utilities that are exposed to potential significant fluctuations in power supply costs, such as Idaho Power.

Q. What other factors do investors consider in their assessment of a company's capital structure?

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[63] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[64] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

[65] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality in a Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[66] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating Idaho Power's financial risk. PPAs and other contractual commitments typically obligate the utility to make specified minimum payments akin to those associated with traditional debt financing, and investors consider a portion of these obligations as debt in evaluating total financial risks.

Similarly, when a utility enters into a mandated PPA with a Qualifying Facility ("QF") under the Public Utility Regulatory Policies Act of 1978, the fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage. As discussed in the testimony of Mr. Keen, Idaho Power's obligations under PPAs with QFs have expanded dramatically in recent years. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

In order to offset the debt equivalent associated with commitments under PPAs with QF developers and other fixed obligations, Idaho Power must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels. These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks.[67] For example, S&P reported that it adjusts Idaho Power's capitalization to include approximately $327 million in imputed debt from PPAs,

[67] *See, e.g.*, Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007); Standard & Poor's Corporation, "Implications of Operating Leases on Analysis of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008); Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).

leases, and postretirement benefit obligations.[68] The capital structure ratios presented earlier do not include imputed debt associated with power purchase agreements or the impact of other off-balance sheet obligations. Unless Idaho Power takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken the Company's creditworthiness, implying a higher required rate of return to compensate investors for the greater risks.[69]

Q. What did you conclude with respect to the Company's capital structure?

A. Based on my evaluation, I concluded that Idaho Power's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Idaho Power's requested common equity ratio of approximately 51 percent is consistent with the range of capitalizations implied for the Utility Proxy Group based on year-end 2010 data and Value Line's near-term projections.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital under reasonable terms so that it can meet the service requirements of its customers. Idaho Power's proposed capital structure is consistent with industry benchmarks and reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company's requested capital structure is

[68] Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (May 14, 2010).

[69] Apart from the immediate impact that the fixed obligation of purchased power costs has on the utility's financial risk, higher fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption.

reinforced by the ongoing uncertainties associated with the utility industry, the magnitude of the Company's fixed obligations (including QF contracts) and the importance of supporting continued investment in system improvements, even during times of adverse industry or market conditions.

C. Return on Equity Recommendation.

Q. Please summarize the results of your analyses.

A. Reflecting the fact that investors' required ROE is unobservable and no single method should be viewed in isolation, I used the DCF, CAPM, and risk premium methods and evaluated comparable earned rates of return expected for utilities. In order to reflect the risks and prospects associated with Idaho Power's jurisdictional electric utility operations, my analyses focused on a proxy group of comparable risk electric utilities. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of low-risk companies in the non-utility sectors of the economy.

My application of the constant growth DCF model considered three alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" growth rate for each firm in the respective proxy groups. In addition, I evaluated the reasonableness of the resulting DCF estimates and eliminated low- and high-end outliers that failed to meet threshold tests of economic logic. My CAPM analyses focused on forward-looking data that best reflects the underlying assumptions of this approach, and my applications of the risk premium and comparable earnings methods focused directly on electric utilities. The results of my alternative analyses are summarized below in Table WEA-6.

TABLE WEA-6
SUMMARY OF QUANTITATIVE RESULTS

	Utility	Non-Utility
DCF		
Earnings Growth		
Value Line	11.4%	11.9%
IBES	10.5%	12.4%
Zacks	10.4%	12.5%
br + sv	9.1%	12.1%
CAPM		
Current Bond Yields	11.8%	10.0%
Projected Bond Yields	12.0%	10.2%
Electric Utility Risk Premium		
Current Bond Yields	10.7%	
Projected Bond Yields	11.3%	
Comparable Earnings		
Value Line 2014-16	10.5%	
Utility Proxy Group	10.4%	

Q. What then is your conclusion as to a fair ROE range for Idaho Power?

A. Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity indicated by my analyses is in the 10.4 percent to 11.4 percent range. After incorporating a minimal adjustment for flotation costs of 15 basis points to my "bare bones" cost of equity range, I concluded that my analyses indicate a fair ROE in the 10.55 percent to 11.55 percent range. As discussed in the testimony of Mr. Keen, Idaho Power is requesting an ROE of 10.50 percent in this case. Because the Company's requested ROE falls near the bottom end of my "bare bones" cost of equity range, it represents a conservative compromise between balancing the impact on customers and the need to provide Idaho Power with a return that is adequate to compensate investors, maintain financial integrity, and attract capital.

Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting the Company's financial position so that Idaho Power remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of maintaining the Company's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers. The reasonableness of the Company's requested ROE is reinforced by the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Qualifications of William E. Avera

July 29, 2011

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance, The University of Texas at Austin (Sep. 1979 to May 1981) Assistant Professor of Finance, (Sep. 1975 to May 1977)	Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.
Assistant Professor of Business, University of North Carolina at Chapel Hill (Sep. 1972 to Jul. 1975)	Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance, University of North Carolina at Chapel Hill (Jan. 1969 to Aug. 1972)	Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics. Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*
B.A., Economics, Emory University, Atlanta, Georgia (Sep. 1961 to Jun. 1965)	Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by

Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
DCF Model – Utility Proxy Group

July 29, 2011

DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend Yield			Growth Rates				Cost of Equity Estimates			
	Company	**Price**	**Dividends**	**Yield**	**V Line**	**IBES**	**Zacks**	**br+sv**	**V Line**	**IBES**	**Zacks**	**br+sv**
1	Ameren Corp.	$ 28.25	$ 1.54	5.5%	-2.0%	-0.7%	4.0%	2.5%	3.5%	4.8%	9.5%	7.9%
2	American Elec Pwr	$ 35.17	$ 1.84	5.2%	3.5%	3.7%	4.0%	4.9%	8.7%	8.9%	9.2%	10.1%
3	Avista Corp.	$ 23.15	$ 1.08	4.7%	8.5%	4.7%	4.7%	3.4%	13.2%	9.4%	9.4%	8.1%
4	Black Hills Corp.	$ 32.44	$ 1.46	4.5%	6.5%	6.0%	6.0%	3.2%	11.0%	10.5%	10.5%	7.7%
5	CenterPoint Energy	$ 17.64	$ 0.79	4.5%	2.5%	5.1%	5.5%	4.5%	7.0%	9.6%	10.0%	8.9%
6	Cleco Corp.	$ 34.58	$ 1.09	3.2%	8.0%	3.0%	7.0%	4.1%	11.2%	6.2%	10.2%	7.3%
7	CMS Energy	$ 19.04	$ 0.84	4.4%	7.0%	5.9%	5.5%	4.7%	11.4%	10.3%	9.9%	9.1%
8	Constellation Energy	$ 33.12	$ 0.96	2.9%	6.0%	3.7%	9.9%	4.7%	8.9%	6.6%	12.8%	7.6%
9	DTE Energy Co.	$ 48.37	$ 2.30	4.8%	5.5%	5.8%	5.0%	3.6%	10.3%	10.6%	9.8%	8.3%
10	Edison International	$ 38.20	$ 1.29	3.4%	-1.0%	4.3%	5.0%	4.7%	2.4%	7.7%	8.4%	8.1%
11	Empire District Elec	$ 21.53	$ 1.28	5.9%	7.0%	NA	NA	2.6%	12.9%	NA	NA	8.5%
12	Great Plains Energy	$ 20.01	$ 0.83	4.1%	6.0%	7.9%	9.0%	2.1%	10.1%	12.0%	13.1%	6.3%
13	Hawaiian Elec.	$ 24.42	$ 1.24	5.1%	11.5%	7.7%	8.6%	4.3%	16.6%	12.8%	13.7%	9.4%
14	IDACORP, Inc.	$ 38.39	$ 1.20	3.1%	5.5%	4.7%	4.7%	4.9%	8.6%	7.8%	7.8%	8.0%
15	Integrys Energy Group	$ 49.62	$ 2.72	5.5%	9.5%	7.5%	10.4%	3.1%	15.0%	13.0%	15.9%	8.6%
16	ITC Holdings Corp.	$ 68.69	$ 1.37	2.0%	14.0%	16.7%	15.0%	13.7%	16.0%	18.7%	17.0%	15.7%
17	Otter Tail Corp.	$ 22.31	$ 1.19	5.3%	17.0%	16.5%	18.0%	3.5%	22.3%	21.8%	23.3%	8.9%
18	Pepco Holdings	$ 18.35	$ 1.08	5.9%	0.5%	7.0%	4.3%	2.0%	6.4%	12.9%	10.2%	7.9%
19	PG&E Corp.	$ 44.06	$ 1.92	4.4%	6.0%	6.3%	5.5%	6.2%	10.4%	10.7%	9.9%	10.6%
20	Pinnacle West Capital	$ 42.53	$ 2.10	4.9%	6.0%	6.4%	4.7%	3.5%	10.9%	11.3%	9.6%	8.4%
21	Portland General Elec.	$ 23.85	$ 1.07	4.5%	3.0%	4.7%	5.2%	3.7%	7.5%	9.2%	9.7%	8.1%
22	TECO Energy	$ 18.68	$ 0.84	4.5%	8.0%	6.1%	5.3%	6.1%	12.5%	10.6%	9.8%	10.6%
23	UIL Holdings	$ 30.19	$ 1.73	5.7%	3.0%	3.1%	2.7%	5.7%	8.7%	8.8%	8.4%	11.4%
24	Westar Energy	$ 25.85	$ 1.28	5.0%	8.5%	6.2%	5.3%	4.6%	13.5%	11.2%	10.3%	9.6%
25	Wisconsin Energy	$ 29.67	$ 1.04	3.5%	7.5%	8.0%	8.0%	5.5%	11.0%	11.5%	11.5%	9.1%
	Average (g)								**11.4%**	**10.5%**	**10.4%**	**9.1%**

(a) www.valueline.com (retrieved Apr. 20, 2011).
(b) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).
(c) *Thomson ReutersCompany in Context Report (Apr. 19, 2011).*
(d) www.zacks.com (retrieved Apr. 20, 2011).
(e) See Exhibit 403.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Sustainable Growth - Utility Proxy Group

July 29, 2011

BR+SV GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2015					Adjustment			"sv" Factor			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	Ameren Corp.	$2.50	$1.54	$36.50	38.4%	6.8%	1.0188	7.0%	2.7%	0.0104	(0.2167)	-0.23%	**2.5%**
2	American Elec Pwr	$3.75	$2.10	$36.00	44.0%	10.4%	1.0287	10.7%	4.7%	0.0097	0.2000	0.19%	**4.9%**
3	Avista Corp.	$2.00	$1.30	$22.50	35.0%	8.9%	1.0177	9.0%	3.2%	0.0126	0.1818	0.23%	**3.4%**
4	Black Hills Corp.	$2.50	$1.55	$30.75	38.0%	8.1%	1.0125	8.2%	3.1%	0.0048	0.0538	0.03%	**3.2%**
5	CenterPoint Energy	$1.30	$0.90	$9.75	30.8%	13.3%	1.0253	13.7%	4.2%	0.0051	0.5125	0.26%	**4.5%**
6	Cleco Corp.	$2.75	$1.60	$28.50	41.8%	9.6%	1.0265	9.9%	4.1%	-	0.1231	0.00%	**4.1%**
7	CMS Energy	$1.75	$1.10	$14.75	37.1%	11.9%	1.0300	12.2%	4.5%	0.0063	0.3140	0.20%	**4.7%**
8	Constellation Energy	$3.25	$1.00	$47.75	69.2%	6.8%	1.0250	7.0%	4.8%	0.0083	(0.1938)	-0.16%	**4.7%**
9	DTE Energy Co.	$4.25	$2.70	$46.50	36.5%	9.1%	1.0200	9.3%	3.4%	0.0086	0.1913	0.16%	**3.6%**
10	Edison International	$3.25	$1.40	$40.25	56.9%	8.1%	1.0198	8.2%	4.7%	-	(0.0063)	0.00%	**4.7%**
11	Empire District Elec	$1.75	$1.35	$17.50	22.9%	10.0%	1.0119	10.1%	2.3%	0.0080	0.3000	0.24%	**2.6%**
12	Great Plains Energy	$1.75	$1.20	$23.50	31.4%	7.4%	1.0231	7.6%	2.4%	0.0241	(0.1190)	-0.29%	**2.1%**
13	Hawaiian Elec.	$2.00	$1.30	$18.00	35.0%	11.1%	1.0183	11.3%	4.0%	0.0127	0.2653	0.34%	**4.3%**
14	IDACORP, Inc.	$3.10	$1.40	$36.50	54.8%	8.5%	1.0230	8.7%	4.8%	0.0131	0.0875	0.11%	**4.9%**
15	Integrys Energy Group	$4.00	$2.72	$42.75	32.0%	9.4%	1.0141	9.5%	3.0%	0.0033	0.1000	0.03%	**3.1%**
16	ITC Holdings Corp.	$5.50	$1.75	$35.50	68.2%	15.5%	1.0553	16.4%	11.1%	0.0398	0.6359	2.53%	**13.7%**
17	Otter Tail Corp.	$1.85	$1.30	$21.45	29.7%	8.6%	1.0353	8.9%	2.7%	0.0401	0.2200	0.88%	**3.5%**
18	Pepco Holdings	$1.55	$1.12	$21.60	27.7%	7.2%	1.0210	7.3%	2.0%	0.0126	(0.0286)	-0.04%	**2.0%**
19	PG&E Corp.	$4.25	$2.20	$36.25	48.2%	11.7%	1.0306	12.1%	5.8%	0.0162	0.2368	0.38%	**6.2%**
20	Pinnacle West Capital	$3.50	$2.30	$38.25	34.3%	9.2%	1.0227	9.4%	3.2%	0.0264	0.1000	0.26%	**3.5%**
21	Portland General Elec.	$2.00	$1.20	$23.75	40.0%	8.4%	1.0291	8.7%	3.5%	0.0382	0.0500	0.19%	**3.7%**
22	TECO Energy	$1.75	$1.00	$13.25	42.9%	13.2%	1.0289	13.6%	5.8%	0.0075	0.3690	0.28%	**6.1%**
23	UIL Holdings	$2.35	$1.73	$27.00	26.4%	8.7%	1.0819	9.4%	2.5%	0.1394	0.2286	3.19%	**5.7%**
24	Westar Energy	$2.40	$1.44	$24.00	40.0%	10.0%	1.0207	10.2%	4.1%	0.0275	0.2000	0.55%	**4.6%**
25	Wisconsin Energy	$2.50	$1.40	$20.25	44.0%	12.3%	1.0215	12.6%	5.5%	-	0.4600	0.00%	**5.5%**

BR+SV GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2010			2015			Chg	2015 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2010	2015	Growth
1	Ameren Corp.	50.9%	$15,185	$7,729	53.0%	$17,600	$9,328	3.8%	$35.00	$25.00	$30.00	0.822	240.40	256.00	1.27%
2	American Elec Pwr	46.5%	$29,185	$13,571	50.5%	$35,800	$18,079	5.9%	$55.00	$35.00	$45.00	1.250	481.00	500.00	0.78%
3	Avista Corp.	51.5%	$2,200	$1,133	52.0%	$2,600	$1,352	3.6%	$30.00	$25.00	$27.50	1.222	57.00	60.00	1.03%
4	Black Hills Corp.	50.0%	$2,425	$1,213	49.5%	$2,775	$1,374	2.5%	$40.00	$25.00	$32.50	1.057	43.75	44.75	0.45%
5	CenterPoint Energy	26.2%	$12,199	$3,196	29.0%	$14,200	$4,118	5.2%	$25.00	$15.00	$20.00	2.051	424.70	430.00	0.25%
6	Cleco Corp.	48.5%	$2,718	$1,318	55.0%	$3,125	$1,719	5.5%	$40.00	$25.00	$32.50	1.140	60.75	60.75	0.00%
7	CMS Energy	29.5%	$9,473	$2,795	34.0%	$11,100	$3,774	6.2%	$25.00	$18.00	$21.50	1.458	249.60	255.00	0.43%
8	Constellation Energy	62.8%	$12,468	$7,830	67.5%	$14,900	$10,058	5.1%	$50.00	$30.00	$40.00	0.838	199.00	209.00	0.99%
9	DTE Energy Co.	48.7%	$13,811	$6,726	47.5%	$17,300	$8,218	4.1%	$70.00	$45.00	$57.50	1.237	170.00	176.00	0.70%
10	Edison International	45.5%	$23,600	$10,738	45.0%	$29,100	$13,095	4.0%	$50.00	$30.00	$40.00	0.994	325.81	325.81	0.00%
11	Empire District Elec	48.7%	$1,351	$658	52.0%	$1,425	$741	2.4%	$30.00	$20.00	$25.00	1.429	41.58	42.75	0.56%
12	Great Plains Energy	49.2%	$5,868	$2,887	48.5%	$7,500	$3,638	4.7%	$25.00	$17.00	$21.00	0.894	135.71	155.00	2.69%
13	Hawaiian Elec.	54.5%	$2,740	$1,493	52.0%	$3,450	$1,794	3.7%	$30.00	$19.00	$24.50	1.361	94.50	99.00	0.93%
14	IDACORP, Inc.	51.0%	$2,950	$1,505	50.5%	$3,750	$1,894	4.7%	$50.00	$30.00	$40.00	1.096	49.00	52.00	1.20%
15	Integrys Energy Group	56.8%	$5,119	$2,907	54.0%	$6,200	$3,348	2.9%	$55.00	$40.00	$47.50	1.111	77.35	78.50	0.30%
16	ITC Holdings Corp.	30.9%	$3,614	$1,117	33.5%	$5,800	$1,943	11.7%	$115.00	$80.00	$97.50	2.746	50.72	54.50	1.45%
17	Otter Tail Corp.	59.2%	$1,067	$632	61.0%	$1,475	$900	7.3%	$35.00	$20.00	$27.50	1.282	36.00	42.00	3.13%
18	Pepco Holdings	52.5%	$8,000	$4,200	48.0%	$10,800	$5,184	4.3%	$25.00	$17.00	$21.00	0.972	225.00	240.00	1.30%
19	PG&E Corp.	49.5%	$22,575	$11,175	54.0%	$28,100	$15,174	6.3%	$55.00	$40.00	$47.50	1.310	395.00	420.00	1.23%
20	Pinnacle West Capital	56.0%	$6,625	$3,710	53.5%	$8,700	$4,655	4.6%	$50.00	$35.00	$42.50	1.111	108.50	122.00	2.37%
21	Portland General Elec.	47.0%	$3,400	$1,598	50.0%	$4,275	$2,138	6.0%	$30.00	$20.00	$25.00	1.053	75.30	90.00	3.63%
22	TECO Energy	40.8%	$5,318	$2,170	47.5%	$6,100	$2,898	6.0%	$25.00	$17.00	$21.00	1.585	214.90	220.00	0.47%
23	UIL Holdings	47.5%	$1,250	$594	41.5%	$3,250	$1,349	17.8%	$40.00	$30.00	$35.00	1.296	30.00	50.00	10.76%
24	Westar Energy	46.4%	$5,181	$2,404	45.5%	$6,500	$2,958	4.2%	$35.00	$25.00	$30.00	1.250	112.13	125.00	2.20%
25	Wisconsin Energy	49.0%	$7,765	$3,805	48.0%	$9,825	$4,716	4.4%	$45.00	$30.00	$37.50	1.852	233.80	233.80	0.00%

(a) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2015 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2014-16 BVPS.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
DCF Model – Non-Utility Proxy Group

July 29, 2011

DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(c)	(d)	(e)	(e)	(e)	(e)
		Dividend	Growth Rates				Cost of Equity Estimates			
	Company	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	3M Company	2.39%	7.0%	11.9%	11.3%	12.9%	9.4%	14.3%	13.7%	15.3%
2	Abbott Labs.	3.67%	10.0%	8.9%	9.0%	15.0%	13.7%	12.6%	12.7%	18.7%
3	Alberto-Culver	1.02%	15.0%	9.4%	12.5%	8.4%	16.0%	10.4%	13.5%	9.4%
4	AT&T Inc.	6.09%	5.5%	5.7%	7.0%	5.4%	11.6%	11.8%	13.1%	11.5%
5	Automatic Data Proc.	2.93%	8.0%	10.6%	10.8%	9.5%	10.9%	13.5%	13.7%	12.4%
6	Bard (C.R.)	0.77%	9.5%	10.9%	11.8%	18.1%	10.3%	11.7%	12.6%	18.9%
7	Baxter Int'l Inc.	2.45%	10.0%	9.6%	9.3%	15.5%	12.5%	12.1%	11.8%	17.9%
8	Becton, Dickinson	1.97%	9.5%	9.9%	10.8%	9.0%	11.5%	11.9%	12.8%	11.0%
9	Bristol-Myers Squibb	5.11%	8.5%	1.8%	2.0%	5.7%	13.6%	6.9%	7.1%	10.8%
10	Brown-Forman 'B'	1.90%	7.5%	10.9%	13.0%	10.6%	9.4%	12.8%	14.9%	12.5%
11	Chubb Corp.	2.55%	2.5%	8.7%	9.8%	8.0%	5.1%	11.3%	12.4%	10.5%
12	Church & Dwight	0.97%	12.0%	11.8%	12.0%	10.3%	13.0%	12.8%	13.0%	11.3%
13	Coca-Cola	2.80%	9.5%	8.7%	9.0%	9.9%	12.3%	11.5%	11.8%	12.7%
14	Colgate-Palmolive	2.76%	11.0%	9.3%	9.2%	18.1%	13.8%	12.1%	12.0%	20.8%
15	Commerce Bancshs.	2.22%	7.0%	7.0%	7.0%	7.9%	9.2%	9.2%	9.2%	10.1%
16	ConAgra Foods	3.92%	10.5%	7.7%	8.0%	8.1%	14.4%	11.6%	11.9%	12.0%
17	Costco Wholesale	1.24%	7.5%	13.3%	12.9%	8.2%	8.7%	14.5%	14.1%	9.5%
18	Cullen/Frost Bankers	2.96%	4.5%	8.5%	8.0%	5.7%	7.5%	11.5%	11.0%	8.6%
19	CVS Caremark Corp.	1.42%	9.5%	10.1%	12.0%	7.8%	10.9%	11.5%	13.4%	9.2%
20	Ecolab Inc.	1.41%	12.0%	13.2%	13.2%	19.6%	13.4%	14.6%	14.6%	21.0%
21	Exxon Mobil Corp.	2.26%	6.0%	12.1%	8.4%	13.5%	8.3%	14.4%	10.7%	15.7%
22	Gen'l Mills	3.02%	9.5%	7.7%	8.0%	9.3%	12.5%	10.7%	11.0%	12.3%
23	Heinz (H.J.)	3.85%	6.5%	7.0%	8.0%	13.9%	10.4%	10.9%	11.9%	17.8%
24	Hormel Foods	2.01%	10.5%	10.0%	9.3%	10.7%	12.5%	12.0%	11.3%	12.7%
25	Int'l Business Mach.	1.77%	13.0%	11.5%	9.3%	20.4%	14.8%	13.3%	11.1%	22.2%
26	Johnson & Johnson	3.44%	4.5%	6.0%	5.8%	10.8%	7.9%	9.4%	9.2%	14.2%
27	Kellogg	3.14%	9.5%	8.6%	9.0%	9.7%	12.6%	11.7%	12.1%	12.9%
28	Kimberly-Clark	4.09%	6.5%	7.5%	8.7%	18.6%	10.6%	11.6%	12.8%	22.7%
29	Kraft Foods	3.71%	8.0%	8.4%	8.0%	10.7%	11.7%	12.1%	11.7%	14.4%
30	Lilly (Eli)	5.64%	-2.5%	-6.4%	-5.3%	8.4%	3.1%	-0.8%	0.3%	14.0%
31	Lockheed Martin	3.78%	10.0%	8.1%	6.8%	20.3%	13.8%	11.9%	10.6%	24.1%
32	McCormick & Co.	2.24%	8.5%	9.6%	9.5%	13.3%	10.7%	11.8%	11.7%	15.6%
33	McDonald's Corp.	3.25%	9.5%	9.8%	9.3%	10.7%	12.8%	13.1%	12.6%	13.9%
34	McKesson Corp.	0.98%	10.0%	14.2%	11.0%	11.7%	11.0%	15.2%	12.0%	12.7%
35	Medtronic, Inc.	2.47%	7.5%	8.8%	8.4%	11.7%	10.0%	11.3%	10.9%	14.1%
36	Microsoft Corp.	2.26%	12.5%	11.3%	11.7%	15.3%	14.8%	13.6%	14.0%	17.5%
37	NIKE, Inc. 'B'	1.49%	9.5%	10.9%	12.5%	12.2%	11.0%	12.4%	14.0%	13.7%
38	Northrop Grumman	2.82%	12.5%	11.0%	11.1%	7.9%	15.3%	13.8%	13.9%	10.7%
39	PepsiCo, Inc.	2.91%	11.0%	8.9%	9.5%	14.5%	13.9%	11.8%	12.4%	17.4%
40	Pfizer, Inc.	4.50%	5.0%	2.8%	3.5%	7.0%	9.5%	7.3%	8.0%	11.5%
41	Procter & Gamble	3.01%	8.0%	8.9%	9.2%	7.2%	11.0%	11.9%	12.2%	10.3%
42	Raytheon Co.	3.02%	10.0%	8.0%	10.0%	8.6%	13.0%	11.0%	13.0%	11.6%
43	Stryker Corp.	1.26%	12.5%	10.9%	11.4%	13.6%	13.8%	12.2%	12.7%	14.9%
44	Sysco Corp.	3.47%	8.0%	10.0%	9.7%	14.2%	11.5%	13.5%	13.2%	17.6%
45	TJX Companies	1.28%	13.5%	14.5%	14.4%	11.1%	14.8%	15.8%	15.7%	12.4%
46	United Parcel Serv.	2.59%	9.0%	11.7%	11.5%	17.9%	11.6%	14.3%	14.1%	20.5%
47	Verizon Communic.	5.63%	4.0%	6.2%	14.9%	5.7%	9.6%	11.8%	20.5%	11.3%
48	Walgreen Co.	1.68%	11.5%	13.4%	13.0%	8.4%	13.2%	15.1%	14.7%	10.1%
49	Wal-Mart Stores	2.16%	10.0%	10.7%	11.3%	9.9%	12.2%	12.9%	13.5%	12.1%
50	Waste Management	3.52%	5.5%	9.6%	11.0%	5.2%	9.0%	13.1%	14.5%	8.7%
	Average (f)						**11.9%**	**12.4%**	**12.5%**	**12.1%**

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) *Thomson Reuters Company in Context Report* (Jan. 28, 2011).
(c) www.zacks.com (retrieved Jan. 31, 2011).
(d) See Exhibit 405.
(e) Sum of dividend yield and respective growth rate.
(f) Excludes highlighted figures.

Idaho Power/405
Witness: William E. Avera

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Sustainable Growth – Non-Utility Proxy Group

July 29, 2011

BR+SV GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		--------- 2014 --------					Adjust.			--------- "sv" Factor --------			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adj. r**	**br**	**s**	**v**	**sv**	**br + sv**
1	3M Company	$7.60	$3.10	$40.05	59.2%	19.0%	1.0818	20.5%	12.2%	0.0106	0.6731	0.71%	**12.9%**
2	Abbott Labs.	$5.70	$2.18	$22.05	61.8%	25.9%	1.0384	26.8%	16.6%	(0.0197)	0.7900	-1.56%	**15.0%**
3	Alberto-Culver	$2.35	$0.55	$17.85	76.6%	13.2%	1.0315	13.6%	10.4%	(0.0330)	0.6033	-1.99%	**8.4%**
4	AT&T Inc.	$3.25	$2.00	$24.05	38.5%	13.5%	1.0327	14.0%	5.4%	(0.0001)	0.4656	-0.01%	**5.4%**
5	Automatic Data Proc.	$3.45	$1.60	$22.95	53.6%	15.0%	1.0786	16.2%	8.7%	0.0111	0.7039	0.78%	**9.5%**
6	Bard (C.R.)	$7.75	$0.85	$31.45	89.0%	24.6%	1.0255	25.3%	22.5%	(0.0564)	0.7754	-4.37%	**18.1%**
7	Baxter Int'l Inc.	$5.85	$1.50	$22.90	74.4%	25.5%	1.0560	27.0%	20.1%	(0.0633)	0.7224	-4.57%	**15.5%**
8	Becton, Dickinson	$7.65	$2.20	$34.10	71.2%	22.4%	1.0306	23.1%	16.5%	(0.1030)	0.7216	-7.43%	**9.0%**
9	Bristol-Myers Squibb	$2.35	$1.54	$11.65	34.5%	20.2%	1.0263	20.7%	7.1%	(0.0212)	0.6671	-1.42%	**5.7%**
10	Brown-Forman 'B'	$4.50	$1.48	$20.40	67.1%	22.1%	1.0372	22.9%	15.4%	(0.0640)	0.7368	-4.71%	**10.6%**
11	Chubb Corp.	$7.00	$1.60	$64.85	77.1%	10.8%	1.0184	11.0%	8.5%	(0.0319)	0.1632	-0.52%	**8.0%**
12	Church & Dwight	$5.80	$1.00	$39.25	82.8%	14.8%	1.0465	15.5%	12.8%	(0.0414)	0.6075	-2.52%	**10.3%**
13	Coca-Cola	$4.95	$2.48	$18.20	49.9%	27.2%	1.0479	28.5%	14.2%	(0.0526)	0.8267	-4.34%	**9.9%**
14	Colgate-Palmolive	$7.20	$3.20	$13.25	55.6%	54.3%	1.0671	58.0%	32.2%	(0.1557)	0.9086	-14.15%	**18.1%**
15	Commerce Bancshs.	$3.35	$1.15	$32.10	65.7%	10.4%	1.0480	10.9%	7.2%	0.0240	0.2867	0.69%	**7.9%**
16	ConAgra Foods	$2.35	$1.00	$15.00	57.4%	15.7%	1.0288	16.1%	9.3%	(0.0217)	0.5385	-1.17%	**8.1%**
17	Costco Wholesale	$4.20	$0.95	$33.50	77.4%	12.5%	1.0315	12.9%	10.0%	(0.0301)	0.5939	-1.79%	**8.2%**
18	Cullen/Frost Bankers	$4.35	$2.10	$44.00	51.7%	9.9%	1.0382	10.3%	5.3%	0.0132	0.2667	0.35%	**5.7%**
19	CVS Caremark Corp.	$4.00	$0.56	$38.15	86.0%	10.5%	1.0268	10.8%	9.3%	(0.0395)	0.3642	-1.44%	**7.8%**
20	Ecolab Inc.	$3.60	$0.85	$14.45	76.4%	24.9%	1.0530	26.2%	20.0%	(0.0056)	0.7592	-0.43%	**19.6%**
21	Exxon Mobil Corp.	$9.35	$2.05	$45.50	78.1%	20.5%	1.0546	21.7%	16.9%	(0.0578)	0.5956	-3.44%	**13.5%**
22	Gen'l Mills	$3.15	$1.36	$11.95	56.8%	26.4%	1.0318	27.2%	15.5%	(0.0809)	0.7610	-6.16%	**9.3%**
23	Heinz (H.J.)	$4.10	$2.32	$14.65	43.4%	28.0%	1.0908	30.5%	13.3%	0.0085	0.7830	0.66%	**13.9%**
24	Hormel Foods	$2.10	$0.70	$13.55	66.7%	15.5%	1.0527	16.3%	10.9%	(0.0025)	0.6387	-0.16%	**10.7%**
25	Int'l Business Mach.	$18.00	$3.60	$48.75	80.0%	36.9%	1.0856	40.1%	32.1%	(0.1501)	0.7759	-11.65%	**20.4%**
26	Johnson & Johnson	$5.85	$2.65	$27.60	54.7%	21.2%	1.0378	22.0%	12.0%	(0.0185)	0.6846	-1.26%	**10.8%**
27	Kellogg	$5.10	$1.88	$9.95	63.1%	51.3%	1.0352	53.1%	33.5%	(0.2690)	0.8829	-23.75%	**9.7%**
28	Kimberly-Clark	$6.25	$2.75	$15.55	56.0%	40.2%	1.0140	40.8%	22.8%	(0.0506)	0.8363	-4.24%	**18.6%**
29	Kraft Foods	$3.00	$1.40	$24.00	53.3%	12.5%	1.0480	13.1%	7.0%	0.0716	0.5200	3.72%	**10.7%**
30	Lilly (Eli)	$3.40	$2.20	$15.60	35.3%	21.8%	1.0636	23.2%	8.2%	0.0032	0.6716	0.21%	**8.4%**
31	Lockheed Martin	$13.25	$3.50	$31.25	73.6%	42.4%	1.0882	46.1%	34.0%	(0.1663)	0.8188	-13.62%	**20.3%**
32	McCormick & Co.	$3.50	$1.36	$18.95	61.1%	18.5%	1.0649	19.7%	12.0%	0.0178	0.7293	1.30%	**13.3%**
33	McDonald's Corp.	$6.05	$3.00	$19.00	50.4%	31.8%	1.0303	32.8%	16.5%	(0.0734)	0.8000	-5.87%	**10.7%**
34	McKesson Corp.	$6.80	$0.72	$46.65	89.4%	14.6%	1.0421	15.2%	13.6%	(0.0380)	0.4957	-1.88%	**11.7%**
35	Medtronic, Inc.	$4.50	$1.18	$25.95	73.8%	17.3%	1.0597	18.4%	13.6%	(0.0326)	0.5848	-1.91%	**11.7%**
36	Microsoft Corp.	$3.35	$0.96	$10.75	71.3%	31.2%	1.0763	33.5%	23.9%	(0.1104)	0.7850	-8.66%	**15.3%**
37	NIKE, Inc. 'B'	$5.65	$1.50	$34.60	73.5%	16.3%	1.0643	17.4%	12.8%	(0.0085)	0.6358	-0.54%	**12.2%**
38	Northrop Grumman	$10.25	$2.50	$68.00	75.6%	15.1%	1.0293	15.5%	11.7%	(0.0783)	0.4868	-3.81%	**7.9%**
39	PepsiCo, Inc.	$6.40	$2.34	$24.00	63.4%	26.7%	1.0724	28.6%	18.1%	(0.0449)	0.8118	-3.64%	**14.5%**
40	Pfizer, Inc.	$2.05	$1.16	$13.00	43.4%	15.8%	1.0154	16.0%	7.0%	-	0.5273	0.00%	**7.0%**
41	Procter & Gamble	$5.25	$2.18	$29.45	58.5%	17.8%	1.0230	18.2%	10.7%	(0.0495)	0.6900	-3.41%	**7.2%**
42	Raytheon Co.	$7.20	$2.00	$38.65	72.2%	18.6%	1.0231	19.1%	13.8%	(0.0870)	0.5932	-5.16%	**8.6%**
43	Stryker Corp.	$5.35	$0.84	$32.75	84.3%	16.3%	1.0660	17.4%	14.7%	(0.0144)	0.7213	-1.04%	**13.6%**
44	Sysco Corp.	$2.75	$1.10	$10.10	60.0%	27.2%	1.0502	28.6%	17.2%	(0.0385)	0.7756	-2.98%	**14.2%**
45	TJX Companies	$4.80	$0.80	$12.75	83.3%	37.6%	1.0374	39.1%	32.5%	(0.2565)	0.8355	-21.43%	**11.1%**
46	United Parcel Serv.	$5.50	$2.20	$19.30	60.0%	28.5%	1.0912	31.1%	18.7%	(0.0090)	0.8245	-0.75%	**17.9%**
47	Verizon Communic.	$3.05	$1.96	$18.95	35.7%	16.1%	1.0250	16.5%	5.9%	(0.0032)	0.6555	-0.21%	**5.7%**
48	Walgreen Co.	$3.65	$1.00	$21.15	72.6%	17.3%	1.0252	17.7%	12.8%	(0.0684)	0.6475	-4.43%	**8.4%**
49	Wal-Mart Stores	$6.05	$1.75	$23.40	71.1%	25.9%	1.0072	26.0%	18.5%	(0.1157)	0.7400	-8.56%	**9.9%**
50	Waste Management	$2.90	$1.60	$15.30	44.8%	19.0%	1.0079	19.1%	8.6%	(0.0515)	0.6600	-3.40%	**5.2%**

BR+SV GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)		(g)	(a)	(a)	(f)
		---- Common Equity ----			-------- 2014 Price --------				---- Common Shares ----		
	Company	2009	2014	Chg.	High	Low	Avg.	M/B	2009	2014	Growth
1	3M Company	$12,764	$28,975	17.8%	$135.00	$110.00	$122.50	3.059	710.60	723.00	0.35%
2	Abbott Labs.	$22,856	$33,550	8.0%	$115.00	$95.00	$105.00	4.762	1,551.90	1,520.00	-0.41%
3	Alberto-Culver	$1,197	$1,640	6.5%	$50.00	$40.00	$45.00	2.521	98.26	92.00	-1.31%
4	AT&T Inc.	$102,339	$141,895	6.8%	$50.00	$40.00	$45.00	1.871	5,901.90	5,900.00	-0.01%
5	Automatic Data Proc.	$5,323	$11,700	17.1%	$85.00	$70.00	$77.50	3.377	501.70	510.00	0.33%
6	Bard (C.R.)	$2,194	$2,830	5.2%	$155.00	$125.00	$140.00	4.452	95.92	90.00	-1.27%
7	Baxter Int'l Inc.	$7,191	$12,600	11.9%	$90.00	$75.00	$82.50	3.603	600.97	550.00	-1.76%
8	Becton, Dickinson	$5,143	$6,985	6.3%	$135.00	$110.00	$122.50	3.592	237.08	205.00	-2.87%
9	Bristol-Myers Squibb	$14,785	$19,230	5.4%	$40.00	$30.00	$35.00	3.004	1,709.50	1,650.00	-0.71%
10	Brown-Forman 'B'	$1,895	$2,750	7.7%	$85.00	$70.00	$77.50	3.799	146.96	135.00	-1.68%
11	Chubb Corp.	$15,634	$18,800	3.8%	$85.00	$70.00	$77.50	1.195	332.01	290.00	-2.67%
12	Church & Dwight	$1,602	$2,550	9.7%	$110.00	$90.00	$100.00	2.548	70.55	65.00	-1.63%
13	Coca-Cola	$24,799	$40,035	10.1%	$115.00	$95.00	$105.00	5.769	2,303.00	2,200.00	-0.91%
14	Colgate-Palmolive	$3,116	$6,100	14.4%	$160.00	$130.00	$145.00	10.943	494.17	460.00	-1.42%
15	Commerce Bancshs.	$1,886	$3,050	10.1%	$50.00	$40.00	$45.00	1.402	87.26	95.00	1.71%
16	ConAgra Foods	$4,721	$6,300	5.9%	$35.00	$30.00	$32.50	2.167	441.66	420.00	-1.00%
17	Costco Wholesale	$10,018	$13,725	6.5%	$90.00	$75.00	$82.50	2.463	435.97	410.00	-1.22%
18	Cullen/Frost Bankers	$1,894	$2,775	7.9%	$65.00	$55.00	$60.00	1.364	60.04	63.00	0.97%
19	CVS Caremark Corp.	$35,768	$46,750	5.5%	$65.00	$55.00	$60.00	1.573	1,391.00	1,225.00	-2.51%
20	Ecolab Inc.	$2,001	$3,400	11.2%	$65.00	$55.00	$60.00	4.152	236.60	235.00	-0.14%
21	Exxon Mobil Corp.	$110,569	$191,000	11.6%	$125.00	$100.00	$112.50	2.473	4,727.00	4,200.00	-2.34%
22	Gen'l Mills	$5,175	$7,115	6.6%	$55.00	$45.00	$50.00	4.184	656.00	595.00	-1.93%
23	Heinz (H.J.)	$1,891	$4,700	20.0%	$75.00	$60.00	$67.50	4.608	318.06	321.00	0.18%
24	Hormel Foods	$2,124	$3,600	11.1%	$40.00	$35.00	$37.50	2.768	267.19	266.00	-0.09%
25	Int'l Business Mach.	$22,755	$53,650	18.7%	$240.00	$195.00	$217.50	4.462	1,305.30	1,100.00	-3.36%
26	Johnson & Johnson	$50,588	$73,850	7.9%	$95.00	$80.00	$87.50	3.170	2,754.30	2,675.00	-0.58%
27	Kellogg	$2,272	$3,230	7.3%	$95.00	$75.00	$85.00	8.543	381.38	325.00	-3.15%
28	Kimberly-Clark	$5,406	$6,220	2.8%	$105.00	$85.00	$95.00	6.109	417.00	400.00	-0.83%
29	Kraft Foods	$25,972	$42,000	10.1%	$55.00	$45.00	$50.00	2.083	1,477.90	1,750.00	3.44%
30	Lilly (Eli)	$9,524	$18,000	13.6%	$50.00	$45.00	$47.50	3.045	1,149.00	1,155.00	0.10%
31	Lockheed Martin	$4,129	$10,000	19.4%	$190.00	$155.00	$172.50	5.520	372.90	320.00	-3.01%
32	McCormick & Co.	$1,335	$2,555	13.9%	$75.00	$65.00	$70.00	3.694	131.80	135.00	0.48%
33	McDonald's Corp.	$14,034	$19,000	6.2%	$105.00	$85.00	$95.00	5.000	1,076.70	1,000.00	-1.47%
34	McKesson Corp.	$7,532	$11,480	8.8%	$100.00	$85.00	$92.50	1.983	271.00	246.00	-1.92%
35	Medtronic, Inc.	$14,629	$26,600	12.7%	$70.00	$55.00	$62.50	2.408	1,097.30	1,025.00	-1.35%
36	Microsoft Corp.	$39,558	$85,000	16.5%	$55.00	$45.00	$50.00	4.651	8,908.00	7,900.00	-2.37%
37	NIKE, Inc. 'B'	$8,693	$16,550	13.7%	$105.00	$85.00	$95.00	2.746	485.50	478.00	-0.31%
38	Northrop Grumman	$12,687	$17,000	6.0%	$145.00	$120.00	$132.50	1.949	306.87	250.00	-4.02%
39	PepsiCo, Inc.	$17,442	$36,015	15.6%	$140.00	$115.00	$127.50	5.313	1,565.00	1,500.00	-0.84%
40	Pfizer, Inc.	$90,014	$105,000	3.1%	$30.00	$25.00	$27.50	2.115	8,070.00	8,070.00	0.00%
41	Procter & Gamble	$63,099	$79,455	4.7%	$105.00	$85.00	$95.00	3.226	2,917.00	2,700.00	-1.53%
42	Raytheon Co.	$9,827	$12,375	4.7%	$105.00	$85.00	$95.00	2.458	383.20	320.00	-3.54%
43	Stryker Corp.	$6,595	$12,775	14.1%	$130.00	$105.00	$117.50	3.588	397.90	390.00	-0.40%
44	Sysco Corp.	$3,450	$5,700	10.6%	$50.00	$40.00	$45.00	4.455	590.03	565.00	-0.86%
45	TJX Companies	$2,889	$4,200	7.8%	$85.00	$70.00	$77.50	6.078	409.39	330.00	-4.22%
46	United Parcel Serv.	$7,630	$19,035	20.1%	$120.00	$100.00	$110.00	5.699	992.85	985.00	-0.16%
47	Verizon Communic.	$41,600	$53,439	5.1%	$60.00	$50.00	$55.00	2.902	2,835.70	2,820.00	-0.11%
48	Walgreen Co.	$14,376	$18,500	5.2%	$65.00	$55.00	$60.00	2.837	988.56	875.00	-2.41%
49	Wal-Mart Stores	$70,749	$76,025	1.4%	$100.00	$80.00	$90.00	3.846	3,786.00	3,250.00	-3.01%
50	Waste Management	$6,285	$6,800	1.6%	$50.00	$40.00	$45.00	2.941	486.12	445.00	-1.75%

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of year-end "r" for 2014 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Five-year rate of change.
(g) Average of High and Low expected market prices divided by 2013-15 BVPS.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES)
AND CHARGES FOR ELECTRIC)
SERVICE TO ITS CUSTOMERS IN THE)
STATE OF OREGON.)
)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

STEVEN R. KEEN

July 29, 2011

Q. Please state your name, business address, and present occupation.

A. My name is Steven R. Keen and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company ("Idaho Power" or "Company") as Vice President, Finance and Treasurer.

Q. What is your educational background?

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

Q. Please describe your business experience with Idaho Power.

A. I joined Idaho Power in September 1982 in the Property Accounting Department. In March 1983, I transferred to the Tax Department as a Tax Accountant. From that time through December 1998, I advanced through various positions in the Tax Department, including Property Tax Representative, Tax Research Coordinator, and, finally, Corporate Tax Director. In January 1999, I became President of IDACORP Financial Services. In June of 2006, I accepted the position of Vice President and Treasurer of Idaho Power and IDACORP, Inc. ("IDACORP") and on June 1, 2010, I became Vice President, Finance and Treasurer of Idaho Power and IDACORP.

In the course of my duties with Idaho Power, I presented testimony in Idaho Power's last general rate case before the Public Utility Commission of Oregon ("Commission"), Docket No. UE 213, and the last two general rate cases before the Idaho Public Utilities Commission ("IPUC"), Case Nos. IPC-E-07-08 and IPC-E-08-10, respectively. In addition, I have presented tax testimony to the Internal Revenue Service as well as tax and/or capitalization rate testimony to the Departments of Revenue and Taxation for Idaho, Oregon, Wyoming, and Nevada.

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

A. I oversee the direct financial planning, procurement, and investment of funds for Idaho Power, as well as supervise corporate liquidity management. I also have oversight and responsibility for the Company's financial reporting, both internal and external, and its investor relations function.

My duties and responsibilities include various aspects of all the Company's financings and other financial matters. With respect to long-term financings, sale of bonds, and sale of equity, my duties include development of financial plans with senior officers, meeting with representatives of investment banking firms that are interested in underwriting Idaho Power securities, discussions with credit rating agencies, assisting in preparation of financial material (including Registration Statements filed with the Securities and Exchange Commission), representing the Company at informational meetings for investment banking firms, reviewing information relative to the Company's financings, and recommending disposition of net proceeds. With respect to short-term financings, my duties and responsibilities include negotiation of lines of credit with commercial banks and overseeing the sale of commercial paper.

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

A. Yes. I am in continuous contact with individuals representing investment and commercial banking firms, credit rating agencies, insurance companies, institutional investment firms, and other organizations interested in publicly traded securities, all of whom actively follow IDACORP and Idaho Power. Along with the Company's Chief Financial Officer and the Director of Investor Relations, my responsibilities include keeping these representatives of the financial community informed of the

Company's financial condition, arranging meetings with these individuals and Idaho Power's senior executive management, and visiting with financial representatives in their respective offices. Some of these members of the investment community have followed the electric utility industry for an extended period of time and have a great deal of expertise in the financial problems and prospects of utilities.

Through my continuous contact with the financial community and review of investment banking analytical reports and articles issued by these firms and the rating agencies, I am able to keep informed on trends, interest rates, financing costs, security ratings, and other financial developments in the public utility industry.

Q. Are you a member of any professional societies or associations?

A. Yes. I am a current member and past board president of the Idaho Society of Certified Public Accountants. I am a current member and past council member of the American Institute of Certified Public Accountants. I am a current member and past board chairman of the Associated Taxpayers of Idaho. I am the current board chairman of the Idaho Tax Foundation. I am a member of the Idaho Association for Financial Professionals. Also, in 2008, I was appointed by Idaho Governor Otter to the Board of Commissioners for the Idaho Housing and Finance Association.

In addition to the above activities, I attend numerous conferences and seminars of these and other utility professional groups, such as the Edison Electric Institute, on a regular basis. Through participation in these events, I gain additional information and insights into the financial developments affecting Idaho Power, as well as the electric utility industry.

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

A. My testimony addresses the following issues: (1) financial risk factors generally; (2) risk factors that are unique to Idaho Power which justify the Company's requested return on equity ("ROE") as the minimum acceptable ROE for Idaho Power; (3) the use of a forecasted year-end 2011 capital structure; and (4) the embedded cost of long-term debt and the resultant overall cost of capital used to compute the Company's revenue requirement.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibits 501-503.

I. COST OF EQUITY POINT ESTIMATE

Q. What ROE is the Company requesting in this proceeding?

A. The Company requests an ROE of 10.5 percent.

Q. Is the Company's request consistent with the recommendations made by the Company's outside expert regarding the Company's cost of capital?

A. Yes. The request is within the range suggested by Dr. Avera but at the low end of his "bare bones" recommended range. The Company believes that 10.5 percent is the minimum ROE necessary to allow Idaho Power to attract capital at reasonable rates in today's financial markets.

Q. How did you arrive at your requested ROE?

A. While I believe that the risks facing Idaho Power at this time justify an ROE in excess of 10.5 percent, I have taken into account the general economic conditions in Idaho Power's service area and have selected the lowest end of the recommended range. Idaho Power is sensitive to the burdens imposed upon its customers by the current economic conditions. Accordingly, Idaho Power has adopted a conservative approach in all areas of this rate filing. In that light, the Company is seeking an ROE at 10.5 percent, an amount which the Company believes strikes an appropriate balance between the minimum necessary ROE to continue attracting low-cost capital and the Company's desire to minimize rate impacts for its customers.

Q. Did you consider other ROE decisions in the Oregon jurisdiction?

A. Yes. Idaho Power is aware of the recent ROE of 10.125 percent that was set by stipulation in Pacific Power's last Oregon rate case, UE 217. However, Pacific Power's situation can be distinguished from Idaho Power's, thus justifying a difference in authorized ROE.

Q. Please discuss the differences between Pacific Power and Idaho Power that justify a difference a higher ROE for Idaho Power.

A. Certainly. First, you must consider that Pacific Power's parent company, PacifiCorp, is a larger, multijurisdictional utility. It also carries a higher overall corporate credit rating than Idaho Power with Standard & Poor's Corporation ("S&P"), although Moody's Investors Services, Inc. ("Moody's") rates PacifiCorp and Idaho Power equally. S&P's April 30, 2011, ratings publication assigns PacifiCorp an A- corporate credit rating compared to Idaho Power's BBB. This is a full two step advantage for PacifiCorp and conveys that Idaho Power is viewed as having more risk. Second, the fact that PacifiCorp is owned by MidAmerican Energy Holdings Co., which is privately held and majority owned by Berkshire Hathaway (which carries an AA+ corporate credit rating), was also pointed out in the Standard & Poor's document. Unlike PacifiCorp, Idaho Power does not have a stronger parent company to look to in times of financial distress. In fact, IDACORP's credit metrics are slightly lower than Idaho Power's.

Considering the differences in size and credit quality, there is certainly evidence to support Idaho Power's request for a higher ROE than was granted to Pacific Power. My recommended 10.5 percent ROE is justifiably higher than the Pacific Power decision and at the lower end of the range currently recommended by Dr. Avera.

II. RISK FACTORS

Q. Could you briefly outline the risks confronting the Company that form the basis for your recommendation of a 10.5 percent ROE as the minimum acceptable authorized return?

A. Yes. I will summarize them here and discuss them in greater detail later in my testimony. I believe that, at a minimum, a 10.5 percent ROE is required to properly account for the risks confronting Idaho Power for the following reasons:

1. The general decline in the Company's credit quality and the resulting impact on the Company's ability to meet ongoing capital funding requirements;

2. The Company's difficulty in earning an actual return on equity on a sustained basis that is near the Company's authorized rate of return;

3. The perceived risk in the financial community associated with the variability of the Company's hydroelectric generating base and risks associated with variances in the weather;

4. The costs and risks related to the renewal of federal licenses for the Company's hydroelectric projects, primarily the Hells Canyon Complex, which provides on average 40 percent of the Company's total generating capacity;

5. The impact of large and growing expenditures incurred pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA");

6. The difficulty of the Company to recover on a timely basis the significant capital investment required for present and growing electrical requirements and service reliability for its customers; and

7. The Company's small size and concentrated regulatory risk (i.e., 95 percent of its business is in Idaho).

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

A. Yes. The Company has faced most of these risks for many years. However, their impacts and significance can change (and have changed) and I attempt to address those implications here.

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

A. Yes. There are general financial risks such as increased volatility in the financial markets and what I view as a heightened sensitivity to risk exposure that has evolved since the United States housing market began experiencing problems in 2007, and which was magnified by the very significant disruption in the financial markets that occurred in 2008. There are also industry specific risks, such as unknown costs relative to carbon emissions, an industry-wide need for infrastructure improvements, and increased capital investment, as well as inflationary pressures that increase costs of both operating expenses and capital outlays. While the financial disruption has been somewhat mitigated, particularly in relation to corporate finance in the past year, the improvement has been met with interest rate uncertainty and a growing fear that future borrowing costs could rise dramatically. Recently, the Federal Reserve has indicated that it may be less active in its effort to keep interest rates low, which creates expectations for rising debt costs in the near future. All of these factors combine to create a challenging environment in which the Company must compete with others in the electric utility industry, for both resources and capital, to serve the needs of its customers and shareowners. While I do not intend to elaborate further on more general risks, they are factors worthy of note that point to increased risks for the Company.

A. <u>Declining Credit Ratings</u>.

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

A. Idaho Power's credit ratings as of June 30, 2011, are as follows:

	Standard & Poor's	Moody's
Corporate Credit Rating/ Issuer Rating	BBB	Baa 1
Senior Secured Debt	A-	A2
Senior Unsecured Debt	BBB	Baa 1
Short-Term Tax-Exempt Debt	BBB/A-2	Baa 1
Commercial Paper	A-2	P-2
Credit Facility	None	Baa 1
Rating Outlook	Stable	Stable

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

A. S&P lowered the corporate credit ratings for both Idaho Power and IDACORP from BBB+ to BBB, citing cash flow concerns; the then-current proposed general rate settlement in Idaho, Case No. IPC-E-07-08; and specifically mentioned the impacts of declining load growth. S&P's research update on January 31, 2008, stated:

> The rating action was driven by a gradual deterioration of cash flow coverage and last week's proposed general rate case settlement, which does not sufficiently address long-term ratemaking issues tied to rising costs and load growth pressures. Over time, average credit metrics have deteriorated, and the company has been unable to stabilize returns and cash flow with existing rate mechanisms. The proposed settlement calls for an average 5.2 percent rate increase but does not settle some important, policy-related issues in the case, such as the use of a forecasted test year or the appropriate level of the load growth adjustment credit.

Q. Have there been other recent rating agency actions?

A. Yes. In the intervening time between the S&P action and this filing, both Fitch Ratings and Moody's changed their ratings outlooks for both Idaho Power and

IDACORP from "stable" to "negative" in 2008 then back to "stable" in 2010. On July 8, 2009, Moody's reaffirmed its negative outlook on Idaho Power's corporate credit rating and commented regarding their continued concern:

> Key concerns continue to focus on hydro conditions given the persistence of drought conditions during the past decade and higher than historical average planned capital spending despite recent steps to curtail or delay certain projects. Moreover, while key credit metrics are beginning to trend upward, further strengthening of cash flow and continued conservative financing strategies are necessary to allay our concerns and improve the company's weak position within the Baa1 rating category. To accomplish this, continued support from state regulators in anticipated future general rate cases will also remain an important rating driver.

On March 30, 2010, Moody's revised its outlook for both Idaho Power and IDACORP back to stable with the following comments in a press release:

> The change to a stable rating outlook for IPC reflects the company's strengthened financial and operating profile resulting from a series of regulatory decisions during 2009 and 2010, which evidence a strong support for credit quality.

On the same date, in its updated credit opinion for Idaho Power, Moody's discussed the following regulatory actions in explaining how a supportive regulatory environment bodes well for credit quality:

> Favorable regulatory practices in Idaho, which is IPC's principal jurisdiction, include 1) a relatively swift seven month statutory period governing rate cases; 2) frequent decisions based on settlements instead of litigated proceedings; 3) reasonable allowed returns on equity; 4) reliance on an assortment of cost tracking and adjustment mechanisms, periodic utilization of single-issue rate cases and partially forecast test years to avoid undue rate lag; and 5) pre-approval of future rate treatment for certain capital investments allowed under state law.

Q. Does this indicate that credit ratings of Idaho Power are now on an upward path?

A. No. I do believe recent regulatory actions combined with more positive actual financial results have stopped the decline in Idaho Power's credit ratings. However, I also believe Idaho Power will need to show sustained improved financial results before movement in a positive direction occurs. In the Moody's credit opinion on March 31, 2010, it offered the following comments on what would be required to move the Company's credit ratings upward:

> A rating upgrade is unlikely in the near-to-medium term; however, IPC's rating outlook could turn to positive if the benefits from recent rate relief carry through and there are no material changes in the degree of regulatory supportiveness in future rate filings.

In regard to what could move Idaho Power's ratings down, Moody's commented:

> The rating would likely be revised downward if the recently improved regulatory support wanes or if conservative funding strategies are not adhered to, thereby contributing to undue pressure on metrics.

Moody's also offered specific comments regarding cash flow metrics, indicating that sustainable levels of improvement would be needed to support a positive outlook and that poor metrics for an extended period of time could result in a ratings downgrade.

Q. Did S&P's offer any similar comments?

A. Yes. In S&P's May 20, 2011, research report, the agency noted the following in its credit outlook:

> The stable outlook reflects our expectation of sufficient operating cash flows to support financial metrics that are adequate for the ratings, the ability to internally fund a significant portion of capital expenditures, and adequate management of regulatory relationships. We could lower the ratings if the company does not carefully manage costs and investments to ensure full recovery and the maintenance of credit metrics, especially in light of a weakening economy. We could raise the ratings if the

> company is able to consistently achieve significantly stronger financial metrics, including adjusted FFO to debt of 20% or more and adjusted debt to capital of 50% or less, in addition to solidly managing regulatory relationships, but higher ratings are unlikely in the near term.

Q. Given the views of the rating agencies, do you believe that the current credit ratings of Idaho Power are adequate?

A. Yes. Idaho Power is able to raise capital in today's markets with its current ratings. However, new debt/bond issues are at a higher cost than if Idaho Power's credit ratings were higher (i.e., the higher the credit rating, the lower the debt financing cost).

Moreover, with Idaho Power's current credit rating level, an unexpected downgrade in credit could have significant financial impacts. Should an unexpected or unforeseen event cause Idaho Power's short-term credit ratings to be lowered, it could become extremely difficult for the Company to issue commercial paper. The commercial paper market is very competitive, and a reduction to the Company's short-term credit rating would make its commercial paper illiquid in the market and more expensive to issue. This would significantly limit the options Idaho Power has available to meet ongoing cash requirements, such as funding capital improvements and paying for power supply costs in excess of those recovered in base rates, and would likely result in higher interest costs that ultimately flow through to the Company's customers. The Company's annual and quarterly financial statement disclosures list risk factors which identify potential events that could have an impact on the Company. While the list is extensive, it may not identify every possible risk that could occur. These unexpected or unforeseen risks have the potential to cause greater financial impact when a company is closer to the bottom of what is considered "investment grade."

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

A. For S&P that rating is BBB-. Idaho Power's corporate credit rating is currently one step above that bottom rating. Its senior unsecured debt rating is at BBB and its secured debt rating is currently at A-. A significant concern for me, as the officer primarily responsible for providing the Company's capital, is how close Idaho Power is to the bottom of investment grade status.

Q. Can you illustrate the recent trend in ratings for the Company and show the relationship to the level that is considered investment grade?

A. Yes. I have sponsored Exhibit 501, which shows the downward trend to Company ratings and shows how close the current ratings are to the bottom level for investment grade companies.

B. <u>Reasonable Actual Results</u>.

Q. Do you have an opinion as to why the rating agencies have taken their previous actions to reduce Idaho Power's credit ratings?

A. Yes, I do. I believe the single largest contributor is the fact that the Company's actual results have been significantly and consistently below its authorized rate of return.

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

A. No. The Company has not been able to earn its allowed ROE on a system-wide basis, and the ROE in its Oregon jurisdiction has been even lower. The system-wide actual ROE was 7.2 percent in 2004 and 7.7 percent in 2005. In 2006, Idaho Power's actual ROE was just over 9 percent because of excellent hydro conditions. In the next three years, Idaho Power earned 6.9 percent, 7.9 percent, and 9.6 percent ROE on a total system-wide basis. In 2010, the total system ROE was 10 percent; however, it would have only been 7.9 percent if not for a one-time tax benefit, which I will discuss later in my testimony.

For the Oregon jurisdiction during the years 2005 to 2009, Idaho Power's authorized ROE in Oregon was 10 percent. The Company's Oregon jurisdiction normalized ROE ranged from a high of 4.30 percent in 2005 to a low of -3.58 percent in 2008. In 2010, the OPUC revised Idaho Power's Oregon authorized ROE to 10.175 percent but its normalized Oregon ROE was 6.32 percent (without the one-time tax benefit).

The gap between allowed and actual ROE is quite evident when placed on a graph, as depicted in Mr. Darrel Anderson's Exhibit 201.

Q. How is this continual earnings short-fall perceived in the financial community?

A. I believe that the financial community and the rating agencies are both focused on and concerned about this short-fall. Recent ratings actions are looking directly at the actual results of Idaho Power's regulatory efforts. Both the investment community and the ratings agencies expect actual rates of return to be near authorized levels, or at least to occur at or above authorized levels as often as they fall below them. They are both also looking for more consistency in cash flows.

Q. What are the impacts if ratings agencies and financial markets are continually disappointed with actual results?

A. The impact is that the Company and its customers eventually incur higher costs of capital. Lower ratings actions contribute to higher costs of debt while dissatisfaction in the financial markets can mean lower stock valuation, which leads to greater numbers of equity share issuances, ultimately driving total cost of capital higher.

Q. Did the Company experience any one-time benefits that increased earnings in 2010?

A. Yes. In 2010, the Company recognized a one-time tax benefit for the tax method change related to capitalized repair costs ("Repairs"). A one-time tax benefit of $44.5 million was recorded relating to 2009 and prior tax years. In addition, an $11.7 million tax benefit for the estimated annual deduction was recorded for the 2010 year. This issue remained in dispute with the Internal Revenue Service during 2010; thus, a liability for uncertain tax positions was also accrued relating to these two amounts totaling $14.7 million. With $56.2 million of positive income impacts netted with the uncertain tax position liability of $14.7 million, 2010 results benefited by $41.5 million of additional income.

Q. Will there be ongoing benefits for customers from the Repairs method change that could benefit the Company in future years?

A. Yes. There is an ongoing tax benefit associated with the Repairs deduction; it will provide some benefit to 2011 and the full value of that benefit is included in this rate filing as a decrease to expense. On a total system basis, this benefit effectively lowers the annual request by approximately $8 million more than Idaho Power's prior Repairs deduction methodology would have. In addition, the Company will continue to have the ability to use the Repairs deduction depending upon the amount of investment the Company makes in future qualified repair items.

Q. You mentioned that a liability for uncertain tax positions was established. How is that handled in the future?

A. The issues surrounding the Repairs method change were effectively settled with the Internal Revenue Service in April of 2011. The result of that settlement utilized all but approximately $3 million of the liability. In other words, approximately $12 million of concessions were made, lowering the tax benefit of the Repairs method change, in order to reach agreement. The remaining $3 million of benefit is expected to be recognized in the second quarter of 2011.

Q. Are there any potential one-time adjustments that could benefit customers in 2011?

A. Yes. An additional tax method change relating to the 2009 income tax return occurred in 2010, the income tax benefits of which were offset by recording a liability for uncertain tax positions equal to 100 percent of the benefit. This method change relates to Idaho Power's method of capitalizing overhead costs for tax purposes ("UNICAP"). The method change for UNICAP was not a taxpayer initiated method change but was based on a methodology derived by the Internal Revenue Service. The methodology was new, and while benefiting the Company with additional current tax benefits, it created results similar to a method change proposed by the Company in previous years that was later contested and significantly reduced by the Internal Revenue Service. The size of the change was also of such a magnitude that it elevated Idaho Power's 2009 refund claim to a level that required approval by the U.S. Congress's Joint Committee on Taxation ("Joint Committee"). Given all of these facts, the Company established a liability for uncertain tax positions, which netted against the original claim, bringing the 2010 net tax benefit to $0.

At year end 2010, the gross UNICAP method change impact was approximately $60 million. As time passes, this benefit at inception becomes smaller as depreciation continues to be claimed on the property additions to which the overheads related. The system-wide amount at March 31, 2011, was $58 million; however, additional benefits for new deductions relating to ongoing years will also be recorded if the issue is ultimately approved by the Joint Committee.

In April 2011, the UNICAP issue was submitted along with the rest of the 2009 tax return to the Joint Committee for review. The Company believes submission at this early date enhances the possibility for resolution in 2011. Idaho

Power cannot predict the outcome, but if approval is received, a net benefit in excess of $60 million would be recognized in 2011.

Q. Are the ongoing benefits from the UNICAP method change included in this case similar to the Repairs method change?

A. At this time, they are not included because the Joint Committee has not approved the Company's 2009 refund. However, a UNICAP deduction consistent with Idaho Power's prior method has been included, thus providing some rate benefit. If approval is received from the Joint Committee, it would be appropriate for the increased annual benefits to be included in a general rate case.

Q. Are there other tax benefits that you are aware of that could benefit the current or future periods?

A. At this time, there are no other anticipated or pending method changes that would deliver significant benefits to either 2011 or future years. The Repairs and UNICAP items are unique. It is very unusual to have the impacts from two such adjustments so close together in time.

Q. Does bonus depreciation provide similar benefits to customers the way the UNICAP and Repairs items do?

A. Not necessarily. Bonus depreciation was granted to a broad range of taxpayers, including Idaho Power, and while providing cash benefits to the Company, it does not have income benefits such as either the Repairs or UNICAP methods. Bonus depreciation has been utilized by the federal government, off and on, for the last decade as an economic stimulus measure. The Company has typically taken advantage of the deduction when offered. Cash flow will be benefited in 2011 by the bonus depreciation deduction. Current tax expense will be lower with an offsetting deferred tax that leaves the income impact at $0. The deferred taxes will add to the balance of accumulated deferred income taxes at year end. The accumulated deferred income tax balances, for items included in rate base, are a net reduction to rate base, thus benefiting customers. While bonus depreciation is available in 2011 and 2012, there is no income or return on equity support associated with this deduction.

Q. How do the ratings agencies view the impacts of bonus depreciation?

A. S&P issued an update specifically on bonus depreciation on May 9, 2011. In that report, S&P generally concludes that while bonus depreciation is good for cash flow, it does not have the same positive impact on credit ratings. S&P makes it point strongly with two separate document headings. The first heading reads: "Bonus Depreciation Will Improve Cash Flow . . . ." The second heading continues the thought: ". . . But Not Credit Quality." Under the first heading, S&P points out that bonus depreciation will increase cash flow as well as cash flow metrics. Under the second heading, S&P points out, "However, while we view bonus depreciation as real cash that a company has at its disposal, we minimize its importance in our fundamental credit analysis because it is not sustainable." In Idaho Power's discussions with both Moody's and Standard & Poor's, the agencies stated they found it positive that the Company planned to utilize the additional cash that results from bonus depreciation to minimize existing and future capital funding needs.

Q. Looking ahead, what does Idaho Power believe is the broader implication of the previously discussed one-time tax benefit?

A. The Company has delivered better financial results in recent years, although still below its authorized rates of return, primarily due to the benefits of one-time tax initiatives and earnings support from the Company's previous rate case settlement and stipulation in the Idaho jurisdiction (IPUC Case No. IPC-E-09-30, Order No. 30978). As seen in the prior comments from the ratings agencies, the improved actual results combined with a supportive regulatory environment have been viewed positively. Both the Repairs and UNICAP method changes provide the majority of their value in a single period. They may lift a single year's performance but they do not provide the sustained, ongoing level of support needed by Idaho Power to maintain or enhance its credit quality. Returning to one of my earlier comments, the Company's earnings in 2010 look quite reasonable with a 10 percent actual total system ROE; it is far better than the years immediately prior. However, when the benefits of the Repairs method change are removed for 2010, the actual total system ROE is 7.9 percent. It is this unassisted level of return that requires additional regulatory support and calls for at least the very conservative ROE of 10.5 percent that Idaho Power has requested in this filing.

C. <u>Hydro and Weather Variability</u>.

Q. Please describe the risks specific to Idaho Power's predominately hydroelectric generating base.

A. Idaho Power and its customers have historically enjoyed the benefits of a hydroelectric-based utility, normally deriving more than half of its generation from low cost hydro electricity. The availability of hydroelectric power depends on the amount of snowpack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snowpack run-off, rainfall, temperature, and other weather variability, combined with other stream flow management considerations. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced. Extreme temperatures increase demand for power by customers, who use electricity for cooling and heating, and moderate temperatures decrease demand for power. Precipitation, or the lack thereof, also directly affects the Company's irrigation load, which represents a substantial portion of total system load. Weather and hydro production are inextricably linked. Reduced hydroelectric generation resulting from below normal water flows requires the Company to use more expensive thermal generation and/or purchased power to meet the electrical needs of its customers.

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

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

Q. Has anyone in the financial community attempted to evaluate the risks to the Company posed by its dependence on hydro generation?

A. Yes. While all of the rating agencies and many in the equity analyst community have commented on the significant level of risk the Company faces in regard to its high reliance on hydro power, S&P actually reviewed the hydro issue specifically for Northwest utilities. On January 28, 2008, S&P issued a report titled, "Pacific Northwest Hydrology and Its Impact on Investor-Owned Utilities' Credit Quality." This report took an in-depth look at hydro implications for investor-owned utilities in the Northwest. Regarding Idaho Power, the January 2008 S&P report stated that, "Idaho Power's regulatory mechanisms are strong, relative to the other companies in our survey, but not strong enough to overcome significant exposure to the variable flows of the Snake River." The report went on to indicate the financial implications to the Company related to this and other factors as described below:

> Despite having both a PCA and an update process, the mechanisms have not been able to fully insulate the company from the highly variable and generally low flow

> conditions that have persisted on the Snake River for the greater part of the past decade. Idaho Power's financial performance has been also hampered by a load growth adjustment mechanism that has resulted in a cash loss on new customers, and regulatory lag due to the use of a historical test year for the non-fuel component of rates.

Q. Do the Company's established mechanisms for handling variations in power supply costs remove this weather and water risk?

A. To a large extent, yes. However, because the established mechanisms do not insulate the Company from the effects of 100 percent of all power cost variations, larger variations translate to more volatility for financial results. This higher volatility is viewed as elevated risk by the financial community.

D. <u>Relicensing the Hells Canyon Complex</u>.

Q. Please describe the risks associated with the renewal of federal licenses for the Company's hydroelectric projects.

A. Idaho Power is the only investor-owned electric utility in the United States that, under normal water conditions, derives as much as 55 percent of its Company-owned total system generation from hydro generating facilities. With such a large percentage of the Company's generation resources reliant on hydro facilities, a failure to successfully renew the federal licenses of these facilities could have a dramatic financial impact on the Company and the prices its consumers pay for electricity. For this reason, the Company has committed to expend significant financial and human resources to obtain new Federal Energy Regulatory Commission ("FERC") licenses for its hydro generating capacity.

Q. What are the financial risks associated with the Company's efforts to relicense its hydro generating facilities?

A. Once a relicense application is filed, the utility has no idea as to how long it will be before a final decision is issued by the FERC. This uncertainty, combined with the potential loss of generation capability due to operational requirements, and the magnitude of the financial impact of unknown Protection, Mitigation, and Enhancement ("PM&E") costs create financial risks for the Company.

Q. Are there other hydro relicensing-based financial risks considered by the investment community?

A. Yes. For any particular generating facility, the worst possible outcome would be the loss of the license to a competing party. Along with the uncertainty as to the eventual receipt of licenses and the costs involved in preparing for the license applications, costs of PM&E related to these projects are also difficult to quantify. The potential financial magnitude of these PM&E costs and their effect on the Company's low-cost hydro generation resources threaten the financial stability of a company the size of Idaho Power and the ultimate rates it must charge its customers. These amounts will vary among facilities; however, in all cases, they can be significant due to lost generation capacity, generation at a higher cost, and the decreased ability of the Company to time and control water releases.

If the Company cannot generate when it is most advantageous for the system, then some of the economic value of the generation will be lost even if the amount of total generation does not change. In addition to the hydro relicensing risk, the Company continually faces significant capital, operating, and other costs relating to compliance with current environmental statutes, rules, and regulations. These costs may be even higher in the future as a result of, among other factors, changes in legislation and enforcement policies and the potential additional requirements imposed in connection with the relicensing of the Company's hydroelectric projects.

Q. Please address the risk specifically associated with the Company's relicensing effort before the FERC for the Hells Canyon generating facilities.

A. Idaho Power's Hells Canyon generating facilities, comprised of Hells Canyon, Oxbow, and Brownlee dams, make up 67 percent of the Company's hydro generation capacity and 40 percent of its total generation capacity. The Hells Canyon license application was filed in July 2003 and accepted by the FERC for filing in December 2003. The FERC process moves at a slow and deliberate pace due to the large number of interested parties involved in evaluating the application. Therefore, the timing of the issuance of a new Hells Canyon facilities license remains uncertain. Historically, the FERC has given the Company an annual license renewal (under the existing old license) until the formal new license is issued. It is difficult to predict the ultimate financial impact of the relicense until the new FERC license is issued and all of the relicense conditions are known.

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

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

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

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

Q. What were the accumulated costs related to the Hells Canyon relicensing at December 31, 2010?

A. The total amount the Company had accrued in CWIP was $130.2 million related to Hells Canyon relicensing. Included in this amount was $50.6 million in AFUDC.

Q. Is the Company currently recovering any of these costs from its Oregon customers?

A. No.

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

A. The amounts in CWIP will be transferred to plant in service, the accumulation of AFUDC will cease, and amortization of the investment will begin. Until this investment is included in base rates, the lack of AFUDC and the increase in amortization expense will cause the Company's earnings to decline. The decline would be material given that the December 31, 2010 CWIP balance for Hells Canyon relicensing was $130 million and continues to increase. Because this is a relicense of an existing hydro facility, there will be no increase (and potentially a decrease due to operational changes) in the generation of power and thus no increase in sales revenues. The investment community sees this as a risk that confronts the Company which can be summarized as follows: Upon receipt of a relicense, (1) the Company has an investment (increase in base rates) that has not yet been approved for inclusion in base rates, (2) earnings will go down because AFUDC is no longer being accrued and amortization expense begins, and (3) no additional sales revenues (same plant but new license) will result. If the completion of relicensing is not aligned perfectly with the allowance of new effective rates that recognize the transfer of previously deferred relicensing costs into rate base, the Company will be financially harmed. For the period of time the new rate base is under review by the Commission, the Company will not earn a return on its investment nor recover any recognized amortization expense. This potential regulatory lag combined with any additional potential for some disallowance is a significant risk factor based upon the size of the investment.

E. <u>Risk Associated with Purchase of PURPA Energy</u>.

Q. Does the regulatory treatment of the Company's energy purchases from Qualified Facilities ("QF") increase the financial risk to Idaho Power?

A. Yes. It is important to note that in a very short time frame, the Company has experienced unprecedented growth in the total amount of generation and financial commitments as the result of a high number of agreements it has entered into with PURPA projects, many of which are wind generators. The regulatory treatment of QF expenditures provides for a one-for-one recovery of dollars expended, but does not provide for any return to compensate the Company for this activity. The Company is, in effect, buying and selling energy pursuant to a legal mandate without any compensation for providing this service. Simplistically, this regulatory treatment is similar to requiring a person operating a business to buy a product at the same price it must be sold. The mere dollar-for-dollar recovery of QF expenditures, with no return for the use of the Company's general and administrative resources, balance sheet, and liquidity in managing QF programs, is viewed as a significant risk by the rating agencies. The rating agencies are not making a judgment related to the appropriateness of QF energy purchase programs, but merely pointing out the cost of the financial risk(s) arising from a QF transaction, and that this risk should be reflected in a higher return on equity to credit the Company for its QF contracts.

Q. Do the rating agencies recognize the financial costs of QF-related transactions?

A. Yes. Like other electric utilities, when the Company adds to its rate base, it must use some portion of shareholder equity to fund the investment. The Company must maintain its proportion of equity to debt above a certain level as it continues this investment process. If it does not, the debt level increases and the Company will face the threat of a ratings downgrade. Conversely, when the Company enters into a QF contract for purchased power, an obligation not reflected in its financial statements, an increase in equity is needed to maintain credit quality. Unless an equity component is provided to offset the debt-like obligation of long-term QF purchase power contracts, the Company faces off-balance sheet financial risk. For financial commitments that do not appear on the balance sheet, analysts at S&P impute the debt and interest equivalents on the financial statements of the Company to achieve a more accurate picture of the risk associated with the investment and the Company's related commitment. The added equity needed to offset this imputed debt and interest represents the effect that long-term purchased power commitments have on the cost of capital. Any increase in the long-term obligation of a utility related to its capacity and energy resources will have to be backed by an appropriate amount of equity in the eyes of the ratings agencies.

In reviewing its evaluation of the credit implications of QF-related expenditures, in May of 2003, as stated below, S&P noted that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks.

> Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a 'risk spectrum.' Standard & Poor's applies a 0 percent to 100 percent 'risk factor' to the

> net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.
>
> * * *
>
> Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

Q. Is the Company proposing to be compensated for QF energy it purchases in this docket?

A. No, not directly. However, it is important that the Commission acknowledge the risks posed by the Company's PURPA contract obligations as part of determining an appropriate ROE for the Company.

F. <u>Enhancements and Reliability</u>.

Q. Please describe the risks relative to the Company's ability to recover significant capital investment to fulfill its electrical requirements.

A. As the Company's generation and transmission systems age and customer electrical requirements increase, additional investment is required to maintain reliability standards and to meet the additional requirements on its electrical infrastructure. The Company's year-end 2010 Form 10-K reports a construction budget of between $320 to $330 million in 2011, and between $450 million to $470 million of new construction expenditures over the two-year period of 2012 through 2013. Construction investments of this magnitude introduce two elements of risk. First, there is a risk that the Company may not be able to attract the required capital and, second, the recovery of these investments is on a deferred basis and subject to the regulatory process.

Q. Has growth slowed substantially with the recent recession?

A. Growth has slowed but it has not halted. That said, the Company is facing significant demands associated with the need to maintain a safe, reliable system that satisfies federal and state compliance regulations, reliability requirements, and security mandates. And, as described in greater detail in Mr. Anderson's testimony, these demands impose a financial burden to the Company. The Company still bears significant risk meeting its obligation to safely and reliably serve customers and continues to feel the pressure to raise large amounts of capital requirements. Additionally, efforts at the national level to reshape energy policy may place new upward pressure on spending. New federal energy policies are constantly evolving and will most likely bring additional spending requirements to meet renewable portfolio standards and to comply with expected carbon reducing efforts.

G. <u>Company Size and Geographic Concentration</u>.

Q. Does IDACORP's size have an impact on investor's perceived level of risk?

A. Yes, IDACORP's relatively small market capitalization compared to its peers is a factor that makes IDACORP riskier than the average electric utility holding company. IDACORP's $1.8 billion market capitalization is much smaller than the $7.3 billion dollar average market cap of the electric utilities used by Dr. Avera to estimate the range of acceptable ROEs.[1] There is well-documented evidence that investors in smaller companies expect higher rates of return than larger companies, but also face higher risk.[2] Idaho Power does not have a corporate parent with a large balance

[1] As of April 26, 2011, www.yahoo.com/finance.

[2] See Chapter 7 "Firm Size and Return" of *Ibbotson SBBI 2011 Classic Yearbook*.

sheet and strong credit ratings to rely on during times of financial stress. Also, the Company faces a concentrated regulatory risk compared to many of its peers because 95 percent of its retail revenues come from one jurisdiction (i.e., Idaho). Both equity analysts and the credit agencies consistently identify regulatory risk as one of the chief risk factors for the Company. This lack of diversification, combined with the relatively small size, would argue for a higher required return from investors compared to Idaho Power's peers.

III. CAPITAL STRUCTURE

Q. Would you please describe Exhibit 502?

A. Exhibit 502 details the calculation of Idaho Power's capital structure for long-term debt, the common equity balance resulting from the Company's forecasted year-end 2011 capital structure prepared under my direction, and the resulting recommended overall rate of return.

Q. The capital structure presented on Exhibit 502 incorporates changes to the Company's financial reporting of its capital structure. Could you please discuss the rationale for the variance?

A. For financial reporting purposes, the American Falls Bond Guarantee and the Milner Dam Note Guarantee are included in the long-term debt portion of the capital structure. For ratemaking purposes, the interest costs associated with both the American Falls and the Milner debt securities are treated as operations and maintenance expenses. Even with these exclusions, the capital structure presented in my Exhibit 502 is reasonable in light of industry and rating agency criteria.

Q. What is the Company's proposed cost of debt?

A. As shown on Exhibit 503, which details the calculation of the cost of debt used in the estimated year-end 2011 capital structure, the Company's proposed cost of debt is 5.728 percent.

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

A. Yes. The Company currently utilizes one variable rate security in its long-term capitalization. The Port of Morrow (Boardman) Pollution Control Revenue Bonds Variable Rate Series 2000 ($4.36 million) is listed on line 21 of Exhibit 503.

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

A. This variable rate pollution control bond, although considered a long-term security, has features that allow the Company to take advantage of rates applicable to short-term securities. The interest rate is determined the first day of a weekly period by a Remarketing Agent. The Remarketing Agent examines tax-exempt obligations comparable to the Boardman Variable Bonds known to have been priced or traded under the then-prevailing market conditions and finds the lowest rate which would enable sale of the Boardman Variable Rate Bonds.

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

A. I used actual rates for January through March 2011 and forecasted the remaining 2011 monthly rates. For the forecast, I combined monthly rates from the Securities Industry and Financial Markets Association ("SIFMA") forward curve, a commonly used and accepted industry metric, with the observed spread between the Boardman Variable Rate Bond and the SIFMA rate. The spread I used was 1.25 percent over the SIFMA rate–this was the average spread from mid-April through December of 2010. Prior to this time, the spread was significantly higher. The average rate for the year, when combining the actual and forecasted rates, is 1.55 percent, which is actually lower than the average rate observed for this bond in 2010.

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

A. In the last rate case, the Sweetwater and Humboldt County bonds were in an auction rate mode that reset periodically (every seven days for Sweetwater and every 35 days for Humboldt). The mode had produced short-term rates for the long-dated securities even lower than the Boardman Variable Rate Bonds, and these benefits have been passed on to customers through a lower overall cost of capital structure since 2003. However, in February of 2008, the entire auction rate market began to deteriorate rapidly based on overall credit worries in the market, specifically around the mono-line insurers which guarantee a large portion of the debt in this market. Both the Sweetwater and Humboldt bonds began to experience much higher reset rates through the auction process (e.g., between 7 and 10 percent for Sweetwater). The Company arranged for a short-term loan and used the proceeds to purchase these bonds and hold them in Idaho Power's name. In August of 2009, the Company remarketed these bonds into long fixed rate modes, which are reflected on my Exhibit 503.

Q. Has there been any other significant refinancing in recent years?

A. Yes. In 2010, Idaho Power made a somewhat unusual decision to prefund an obligation for first mortgage bonds that were due in 2011, slightly more than six months early. The prefunding decision required the Company to incur negative carrying costs relative to the investment opportunities that were available. This decision secured some of the lowest long-term financing rates that Idaho Power has ever enjoyed–$100 million at a 3.4 percent coupon for 10 years and $100 million at a 4.85 percent coupon for 30 years. The rates achieved were record setting in the time frame they occurred and will be beneficial to customers for many years to come as the proceeds of this financing were used to prefund near-term construction costs and repay $120 million of outstanding mortgage bonds due on March 2, 2011, that carried a coupon of 6.6 percent. While not listed as a risk factor, opportunities to retire existing bonds with less costly financing will be more difficult in the near term. The next two tranches of first mortgage bonds due for redemption in 2012 and 2013 carry coupons below 5 percent.

Q. Please explain the discrepancy between the Company's actual 2010 debt-to-equity ratio and the projected year-end 2011 debt-to-equity ratio?

A. The projected growth in equity between year-end 2010 and year-end 2011 is based upon two primary factors: (1) the amount of anticipated net income and (2) the possibility of issuing additional equity under the Company's continuing equity program. Currently, there are approximately 1.2 million shares remaining available to be sold under the current sales agency agreement entered into pursuant to IDACORP's continuous equity program. Selling those authorized shares, together with the Company's anticipated net income for 2011, account for the difference between year-end 2010 debt-to-equity ratio and the anticipated year-end 2011 debt-to-equity ratio.

IV. <u>OVERALL COST OF CAPITAL</u>

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

A. As shown on Exhibit 502, using the Company's projected year-end 2011 capital structure, the Company's cost of debt as presented in my testimony, and incorporating the recommended 10.5 percent cost of equity, the resultant overall cost of capital for Idaho Power is 8.17 percent. This is an appropriate rate of return to be utilized by the Commission when deriving the Company's revenue requirement.

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

A. Yes, it does.

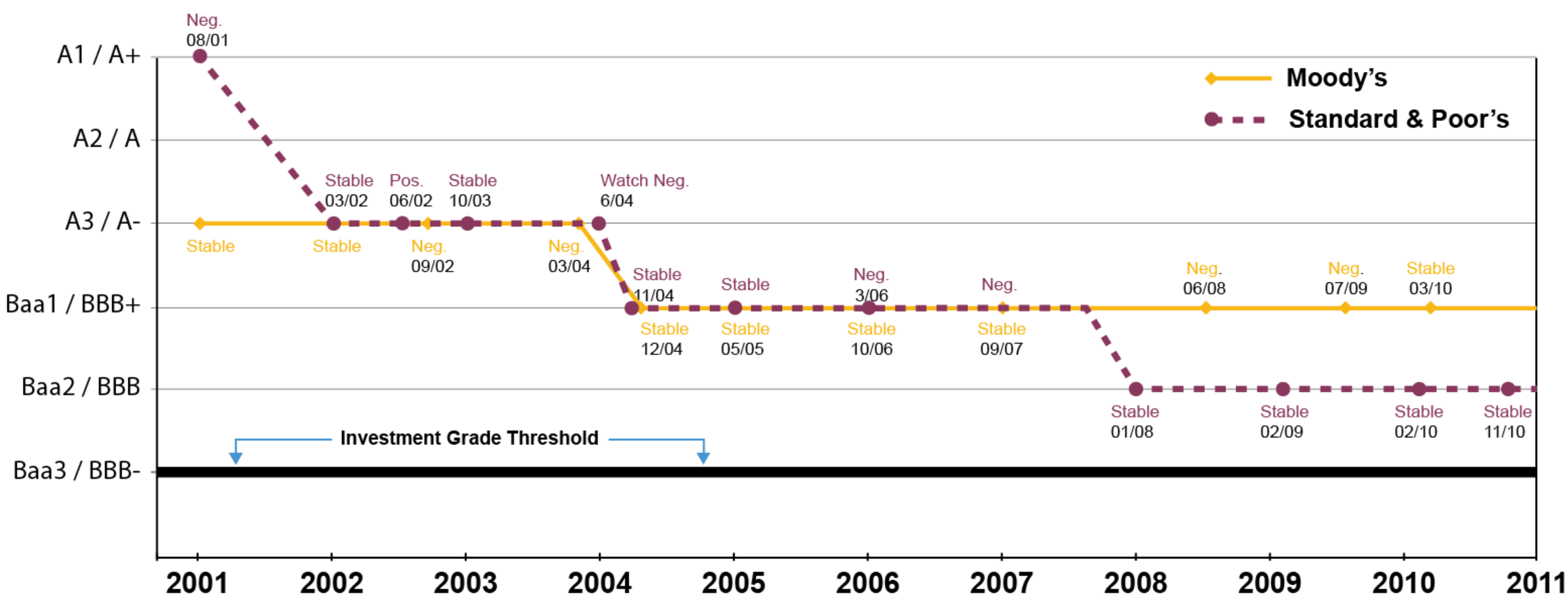
BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Steven R. Keen
Idaho Power Corporate Credit Ratings 2001-2010

July 29, 2011

Idaho Power Corporate Credit Ratings 2001 – 2010



Idaho Power/502
Witness: Steven R. Keen

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Steven R. Keen
Pro Forma Cost of Capital Summarized

July 29, 2011

IDAHO POWER COMPANY

PRO FORMA COST OF CAPITAL
SUMMARIZED
December 31, 2011 Capitalization

	(1)	(2)	(3)	(4)	(5)
Line No		Capitalization Structure Amount	Percent	Embedded Cost	Weighted Cost
1	Long-term Debt	1,465,460,000	48.824%	5.728%	2.797%
2	Preferred Stock	0	0.000%	0.000%	0.000%
3	Common Equity	1,536,028,822	51.176%	10.500% *	5.373%
4	Total Capitalization	$3,001,488,822	100.000%		8.170%

Note:
* Requested Rate of Return

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Steven R. Keen
Pro Forma Cost of Long-Term Debt

July 29, 2011

IDAHO POWER COMPANY
PRO FORMA COST OF LONG-TERM DEBT
As of 12/31/2011
(000's)

Line No.	(1) Class and Series	(2) Coupon Rate	(3) Settlement Date	(4) Maturity Date	(5) Principal Amount Issued	(6) Principal Amount Outstanding	(7) Price	(8) Discount	(9) Issuance Costs	(10) Net Proceeds	(11) Yield To Maturity	(12) Effective Cost
	First Mortgage Bonds:											
1	4.75% Series, due 2012	4.75%	11/15/2002	11/15/2012	100,000	100,000	98.948	1,052.0	1,066.2	97,881.8	5.022%	5,022.0
2	6.00% Series, due 2032	6.00%	11/15/2002	11/15/2032	100,000	100,000	99.456	544.0	1,191.2	98,264.8	6.127%	6,127.1
3	4.25% Series, due 2013	4.25%	5/13/2003	10/1/2013	70,000	70,000	99.465	374.5	641.2	68,984.3	4.425%	3,097.7
4	5.5% Series, due 2033	5.5%	5/13/2003	4/1/2033	70,000	70,000	99.948	36.4	4,335.2	65,628.4	5.949%	4,164.3
5	5.5% Series, due 2034	5.5%	3/26/2004	3/15/2034	50,000	50,000	99.233	383.5	524.4	49,092.1	5.626%	2,813.0
6	5.875% Series, due 2034	5.875%	8/16/2004	8/15/2034	55,000	55,000	98.640	748.0	585.8	53,666.2	6.051%	3,328.2
7	5.30% Series, due 2035	5.30%	8/26/2005	8/15/2035	60,000	60,000	99.319	408.6	3,849.7	55,741.7	5.802%	3,481.3
8	6.30% Series, due 2037	6.30%	6/22/2007	6/15/2037	140,000	140,000	99.801	278.6	1,500.0	138,221.4	6.396%	8,953.9
9	6.25% Series, due 2037	6.25%	10/18/2007	10/15/2037	100,000	100,000	99.732	268.0	1,227.5	98,504.5	6.362%	6,362.3
10	6.025% Series, due 2018	6.025%	7/10/2008	7/15/2018	120,000	120,000	100.000	0.0	1,664.6	118,335.4	6.213%	7,455.6
11	6.15% Series, due 2019	6.15%	3/30/2009	4/1/2019	100,000	100,000	99.815	185.0	1,034.9	98,780.1	6.316%	6,316.3
12	4.50% Series, due 2020	4.50%	11/20/2009	3/1/2020	130,000	130,000	99.819	235.3	1,199.4	128,565.3	4.635%	6,026.0
13	3.40% Series, due 2020	3.40%	8/30/2010	11/1/2020	100,000	100,000	99.501	499.0	1,129.4	98,371.6	3.592%	3,592.2
14	4.85% Series, due 2040	4.85%	8/30/2010	8/15/2040	100,000	100,000	99.830	170.0	1,254.4	98,575.6	4.941%	4,941.5
15												
16	Total First Mortgage Bonds				1,295,000	1,295,000		5,182.9	21,204.1	1,268,613.0	5.650%	71,681.2
17												
18	Pollution Control Revenue Bonds:											
19	Sweetwater 5.25% Series, due 2026	5.25%	8/20/2009	7/15/2026	116,300	116,300	100.000	0.0	8,634.3	107,665.7	5.952%	6,922.2
20	Humboldt 5.15% Series 2003, due 2024	5.15%	8/20/2009	12/1/2024	49,800	49,800	100.000	0.0	4,355.0	45,445.0	6.033%	3,004.5
21	Port of Morrow Series 2000, due 2027	1.55% [1]	5/17/2000	2/1/2027	4,360	4,360	100.000	0.0	170.3	4,189.7	1.731%	75.5
22												
23	Total Pollution Control Revenue Bonds				170,460	170,460		0.0	13,159.7	157,300.3	6.359%	10,002.2
24												
25	TOTAL DEBT CAPITAL				1,465,460	1,465,460		5,182.9	34,363.8	1,425,913.3	5.728%	81,683.3

[1] Forecasted 2011 rate. See Cost of Long-Term Variable Rate Debt schedule.

NOTE: American Falls Dam Bond and Milner Dam Note are guarantees. These instruments are excluded from rate making calculations and therefore are omitted from this schedule.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DOUGLAS N. JONES

July 29, 2011

Q. Please state your name, business address, and present occupation.

A. My name is Douglas N. Jones and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Team Leader of Regulatory Accounting and Support.

Q. What is your educational background?

A. I graduated in 1980 from Boise State University, receiving a Bachelor of Business Administration degree in Accounting. I have also attended numerous accounting, finance, and regulatory courses, including the Edison Electric Institute's advanced ratemaking course, the University of New Mexico's College of Business and Economics Center for Public Utilities basic ratemaking course, and the Financial Accounting Institute's utility finance and accounting course.

Q. Please outline your business experience.

A. Before joining Idaho Power, I spent 14 years in various accounting and supervisory roles for Morrison-Knudsen Company and Ore-Ida Foods. In 1993, I joined Idaho Power as an accountant in the Property Accounting Department. In 2002, I was promoted to Financial Analyst and later, in 2004, to Business Analyst within the Financial Reporting Department under the Regulatory Accounting and Support area. In this last position, I was responsible for modeling, analyzing, and recording of power cost adjustments and deferrals in both Oregon and Idaho. I was also responsible for overseeing all regulatory audits and preparing regulatory analysis and disclosures, both internally and externally, for the Company's quarterly and annual reports. In July 2006, I was promoted to Team Leader of Regulatory Accounting and Support within the Strategic Analysis Department.

Q. What are your duties as Team Leader of Regulatory Accounting and Support?

A. I am responsible for all areas of regulatory reporting and I act as the finance liaison to the Regulatory Affairs Department.

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

A. The purpose of my testimony is two-fold. First, I will present the Company's historical actual audited financial information for the 12-month period ended December 31, 2010. Second, my testimony will discuss the quantification of certain adjustments to operating expenses and rate base consistent with previous Public Utility Commission of Oregon ("OPUC" or "Commission") and Idaho Public Utilities Commission ("IPUC") directives regarding regulatory treatment that result in an adjusted historical actual 12-month period ended December 2010 ("2010 Base").

Q. Please describe the manner in which the 2010 financial data is presented.

A. Actual 2010 financial data is presented using the account names from the Commission-approved Uniform System of Accounts ("USA"). This data has been fully audited and was reported to the Securities and Exchange Commission and the Federal Energy Regulatory Commission ("FERC") in the Company's Form 10-K and FERC Form 1, respectively. The components of the 2010 financial data include the following items: (1) other operating revenues; (2) other revenues and expenses; (3) operation and maintenance expenses; (4) property insurance expenses; (5) regulatory commission expenses; (6) depreciation and amortization expense; (7) electric plant/regulatory assets - amortizations, adjustments, gains, and losses; (8) regulatory debits and credits; (9) taxes other than income taxes; (10) Idaho Energy Resources Company's statement of income and rate base components; (11) electric plant in service and related items; (12) materials and supplies; (13) other deferred programs; (14) accumulated deferred income taxes; (15) customer advances for construction; and (16) certain deductions from operating and maintenance expenses.

Q. Please describe the rationale for quantifying adjustments to the 2010 actual financial data ("2010 Actuals").

A. For the most part, the adjustments I have quantified to 2010 Actuals are in conformance with prior OPUC and IPUC orders and thus have become, in the opinion of the Company, standard regulatory adjustments. The only adjustment that is not the result of prior orders is an adjustment to Other Operating Revenues. I will discuss the rationale for this adjustment later in my testimony.

The Company has made several adjustments to remove specific expenses in conformance with directives of both the OPUC and IPUC. These adjustments provide consistent treatment in both jurisdictions to the benefit of Oregon customers. These adjustments include the removal of general advertising expenses, specific memberships and contributions, certain management expenses, and other exclusions that, although justified for business purposes, may be viewed as more appropriately funded by shareholders than customers and therefore not recoverable through the Company's rates. The following have also been removed: (1) the unamortized portion of the Electric Plant Amortization Adjustment associated with the Prairie Power Rural Electric Cooperative purchase; (2) plant that was determined to no longer be used and useful at the Bridger Coal plant; (3) all 2010 incentive compensation; (4) the financial impacts of both the Oregon and Idaho Energy Efficiency Rider revenues and expenses; and, finally, (5) the removal of amortizations for some preliminary survey and investigation costs, architectural fees, and specific Idaho Intervenor funding that ceased in 2010. Mr. Timothy E. Tatum's testimony addresses the 2011 incentive compensation amount that is included in the test year.

Q. Please describe the Company proposed adjustment to Other Operating Revenues.

A. The Company proposes an adjustment to Other Operating Revenues to reflect an increase to Facilities Charge revenues. In preparation of this case, it was discovered that, in 2010, some revenues received from Schedule 9 customers for facilities charges were recorded to FERC Account 442, Commercial and Industrial Sales, instead of the correct FERC Account 454, Rent from Electric Property. This adjustment corrects that accounting error.

Q. How has the Company treated prepayments in this case?

A. Prepayments have been removed in their entirety, consistent with previous Commission orders. This adjustment is reflected in Ms. Kelley Noe's Exhibit 904.

Q. Are you sponsoring exhibits that contain the 2010 Actuals and 2010 adjustments by the components you have just identified?

A. Yes. I am sponsoring Exhibits 601 through 603 which detail 2010 Actuals and the 2010 adjustments by component categories. The additional adjustments to get from the 2010 Base to the 2011 Test Year, which are also contained in my exhibits, are addressed by Mr. Tatum in his testimony.

Q. Please describe Exhibit 601.

A. Exhibit 601 is a compilation of the Company's supporting schedules for the adjusted historical actual data for the 12-month period ended December 31, 2010.

Q. Please describe page 1 of Exhibit 601.

A. Page 1 of Exhibit 601 reflects the detail for Other Operating Revenues, Accounts 451, 454, and 456.

Q. Please explain the adjustments you have made on page 1 of Exhibit 601, Other Operating revenues, to arrive at the 2010 Base.

A. As discussed earlier in my testimony, the amount included on line 9, column 4 reflects an increase in Facilities Charge revenue to correct for amounts incorrectly booked to FERC Account 442. Because the test year revenue values for Account 442 are developed using forecasted billing determinants, an offsetting adjustment to that account is not needed. The adjustment on line 19, column 4 to the 2010 Actuals removes the impact of the Oregon and Idaho Energy Efficiency Rider revenues (IPUC Order No. 30189).

Q. Please describe pages 2 through 12 of Exhibit 601.

A. Page 2 of Exhibit 601 reflects the detail of Other Revenues and Expenses, Accounts 415 and 416. Pages 3 through 6 reflect the Operation and Maintenance Expenses ("O&M") by USA account. Page 7 reflects the detail of Property Insurance Expense, Account 924. Page 8 reflects the detail of Regulatory Commission Expenses, Account 928. Page 9 includes Depreciation and Amortization Expense, Accounts 403 and 404. Page 10, Electric Plant/Regulatory Assets – Amortizations, Adjustments, Gains, and Losses, Account 406, presents the Prairie Power acquisition amortization adjustment. Page 11 reflects Regulatory Debits and Credits, Accounts 407.3 and 407.4, respectively. Page 12 shows the detail of Taxes Other Than Income Taxes.

Q. Please describe the adjustments quantified on page 12 of Exhibit 601, Taxes Other Than Income Taxes, to arrive at the adjusted 2010 Base.

A. The amounts included on lines 1, 2, and 19 of page 12, column 3 in Exhibit 601 are eliminated by the state and federal payroll loading reversal on line 22, column 3. These amounts represent federal unemployment, Social Security, and state unemployment taxes, respectively. The state and federal payroll loading reversal effectively removes these amounts from Taxes Other Than Income Taxes and spreads them over all accounts that receive labor charges. Therefore, the adjustments in column 4, page 12 eliminate these expenses in their entirety in order to demonstrate that these amounts are not double counted when determining the Company's revenue requirement.

Q. Please describe page 13 of Exhibit 601.

A. Page 13 of Exhibit 601 reflects the net earnings of Idaho Energy Resources Company ("IERCo") that are added to operating income for ratemaking purposes.

Q. Who is IERCo?

A. IERCo is a wholly owned subsidiary of Idaho Power. The primary purpose of IERCo is to mine the coal that fuels the Jim Bridger thermal power plant in Wyoming.

Q. How does the Company treat IERCo's earnings and investment for ratemaking purposes?

A. Consistent with prior Commission orders, the Company treats IERCo's coal operations as a part of its utility operations and, accordingly, adds the current year IERCo earnings to electric operating income and the investment in IERCo to the net electric rate base. Accordingly, the interest expense net of tax (line 13, page 13 of Exhibit 601) on notes payable to Idaho Power has been added back to IERCo's Net Income from Operations. Additionally, the notes payable (column 5, page 21 of Exhibit 601) to Idaho Power have been added to IERCo's rate base in determining the Company's net investment in IERCo to be included in total system rate base.

Q. Please describe the adjustments to IERCo's net earnings and rate base in this proceeding.

A. Adjustments were made to increase IERCo's rate base for notes payable to Idaho Power in the amount of $19,880,651 (column 5, line 14, page 21 of Exhibit 601) and the associated interest expense adjustment net of income tax of $29,165 (column 3, line 13, page 13 of Exhibit 601) in order for IERCo's rate base and earnings to reflect only the cash required to fund IERCo operations for the year 2010. If IERCo were to use these funds to make a distribution of earnings to the Company, or if the Company were to actually fold IERCo into its own operations, the result would be the same as presented herein.

Q. Please describe the data contained on pages 14 through 21 of Exhibit 601?

A. Pages 14 through 21 of Exhibit 601 reflect the development of all components applicable to the combined system rate base of the Company for the test year 2011 as directed by Mr. Tatum. Page 14 reflects the balance by month and the 13-month average of Electric Plant in Service, Account 101. Page 15 reflects the balance by month and the 13-month average of Accumulated Provision for Depreciation, Account 108. Page 16 reflects the balance by month and the 13-month average of Accumulated Provision for Amortization, Account 111. Page 17 reflects the balance by month and the 13-month average of Materials and Supplies, Accounts 154 and 163. Page 18 reflects the balance of the Company's Other Deferred Programs. For these programs, the Company has included the December 31, 2010, ending balance in rate base, consistent with previous orders.

Q. Please describe in more detail Other Deferred Programs on page 18 of Exhibit 601.

A. Previous Commission-approved programs included on page 18 of Exhibit 601 are the American Falls bond refinancing costs (IPUC Order No. 25880) and Intervenor funding costs (IPUC Order No. 30722). The American Falls bond refinancing is being amortized over the life of the American Falls bond and will be fully amortized in 2025. The Intervenor funding costs are assumed to be amortized and recovered over a one-year period.

Also included on Exhibit 601 is the Citizens' Utility Board of Oregon's 2010 Fund Grant (OPUC Order No. 10-406), the Statement of Financial Accounting Standards 87 capitalized pension costs (OPUC Order No. 10-064), Oregon's unamortized jurisdictional portion of the Grid West loans (OPUC Order No.06-483), and the FERC's unamortized jurisdictional portion of the Grid West loans.

Q. Please describe the remaining pages in Exhibit 601.

A. Page 19 of Exhibit 601 reflects the balance at the beginning and end of 2010 and the average balance for Accumulated Deferred Income Taxes, Accounts 190, 282, and 283. Page 20 reflects the balance by month and the 13-month average balance of Customer Advances for Construction, Account 252. Page 21 reflects the balance by month and 13-month average of the rate base components for IERCo consistent with prior OPUC and IPUC orders.

Q. Please describe Exhibit 602.

A. Exhibit 602 reflects the detailed support of deductions from the O&M expense of the Company for general advertising expenses, certain memberships and contributions, senior management expenses, and miscellaneous other expenses. This screening process is consistent with previous Oregon and Idaho general rate case filings.

Q. Please describe in more detail pages 2 through 10 of Exhibit 602.

A. The Company has put processes in place to review and screen its accounting records to identify memberships and contributions in an effort to properly identify, account for, and share the costs of each. All contributions and one-third to 100 percent of certain memberships have been removed. This screening process is consistent with previous Oregon and Idaho general rate case filings. Additionally, senior management expenses have been reviewed and adjusted by (1) removing 100 percent of all charges to the Arid Club, (2) removing one-third of Edison Electric Institute expenses, and (3) allocating the balance of expense account charges of senior management between Idaho Power and IDACORP on the basis of how their payroll is charged. Five officers had no further allocation based on payroll because they either incurred no expenses, their management responsibilities are solely incurred on behalf of Idaho Power, or their expenses are reviewed monthly for proper allocation between IDACORP and Idaho Power, thus not requiring further allocation. Lastly, the Company has reviewed all expense account charges to O&M in an effort to identify and exclude charges from regulatory recovery based on prior concerns expressed in previous Idaho general rate case filings based solely on the name of the business establishment. While these expense account charges are legitimate business expenses, out of an abundance of caution, they were removed.

Q. Please describe Exhibit 603.

A. Exhibit 603 was developed to identify and include or exclude specific rate base, revenue, and expense adjustments which have not been provided for elsewhere. These and/or similar adjustments have been made in previous general rate cases.

Q. Please describe the adjustments you have included in this Exhibit 603.

A. Lines 1 through 3 of Exhibit 603 reflect the unamortized portion of the Electric Plant Acquisition Adjustment associated with the Prairie Power Rural Electric Cooperative purchase in July 1992.

Line 4 of Exhibit 603 reflects a decrease to Investment in Associated Companies (IERCo), Account 123, for a portion of plant deemed not used and useful at the Bridger Coal plant, per IPUC Order No. 29505.

Lines 5 through 7 of Exhibit 603 reflect increases due to forecasted pension expense amortization that is discussed in Mr. Tatum's testimony.

Lines 8, 9, 10, and 11 of Exhibit 603 remove the income statement impact of the Idaho Energy Efficiency Rider (formerly DSM Rider) accounting affecting Other Electric Revenues, Account 456, and Customer Assistance Expenses, Account 908, in accordance with IPUC Order No. 30189. While the purpose of these entries is to demonstrate that the Energy Efficiency Rider revenues and expenses have been excluded from the revenue requirement, leaving these amounts in the income statement would have had no impact to the revenue requirement since they are a net zero adjustment.

Line 12 of Exhibit 603 removes the 2010 amortization of the deferred Preliminary Survey and Engineering costs that will not recur in 2011 because the deferred balance will be fully amortized in September 2010.

Line 13 of Exhibit 603 removes all 2010 incentives included in Administrative and General Salaries, Account 920. Test year 2011 incentive expense for which the Company seeks recovery is addressed in Mr. Tatum's testimony.

Line 14 of Exhibit 603 removes the 2010 amortization of the deferred architectural fees that will not recur in 2011 because the deferred balance will be fully amortized in November 2010.

Lines 15 through 22 of Exhibit 603 include the 2011 projected Intervenor funding amortization that is discussed in detail in Mr. Tatum's testimony and reflected in his exhibits.

Lines 23 and 24 of Exhibit 603 remove the 2010 amortization of deferred Intervenor funding that will not recur in 2011 because the deferred balances will be fully amortized in January 2010.

Q. Are all the data and associated adjustments made to your exhibits and supporting schedules calculated on a total system basis?

A. Yes.

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

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Douglas N. Jones
Adjusted Historical Actual Financial Data

July 29, 2011

IDAHO POWER COMPANY
OTHER OPERATING REVENUES
For Twelve Months Ended December 31, 2011

(1) Line No	(2) Description	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
1	Miscellaneous service revenues (451)	$ 3,532,832	$ -	$ 3,532,832	YES	$ -	$ -		$ 3,532,832	$ -	$ 3,532,832
	Rent from electric property (454):										
2	Substation equipment	9,968,654	-	9,968,654	YES	-	-		9,968,654	-	9,968,654
3	Transformer & distribution rentals	17,330	-	17,330	YES	-	-		17,330	-	17,330
4	Station and line rentals	2,067,177	-	2,067,177	YES	-	-		2,067,177	-	2,067,177
5	Cogeneration and small power production	659,903	-	659,903		197,439	197,439		857,342	-	857,342
6	Real estate rents	240,575	-	240,575	YES	-	-		240,575	-	240,575
7	Dark fiber rents	448,000	-	448,000	YES	-	-		448,000	-	448,000
8	Joint pole attachments	1,660,518	-	1,660,518	YES	-	-		1,660,518	-	1,660,518
9	Facilities charges	5,740,276	1,786,566	7,526,842		(1,214,026)	(1,214,026)		6,312,816	-	6,312,816
10	Overnight park rents	338,693	-	338,693	YES	-	-		338,693	-	338,693
11	Miscellaneous	-	-	-		-	-		-	-	-
12	Total rent from electric property	21,141,126	1,786,566	22,927,692		(1,016,587)	(1,016,587)		21,911,105	-	21,911,105
	Other electric revenue (456):										
13	Network Service	4,739,971	-	4,739,971		739,280	739,280		5,479,251	-	5,479,251
14	Point - to - Point and other services	10,658,431	-	10,658,431		1,799,219	1,799,219		12,457,650	-	12,457,650
15	Photovoltaic	5,007	-	5,007	YES	-	-		5,007	-	5,007
16	Antelope	73,824	-	73,824	YES	-	-		73,824	-	73,824
17	Sierra Pacific Power Company sales	(55,846)	-	(55,846)		55,846	55,846		-	-	-
18	Stand-by service	309,185	-	309,185	YES	-	-		309,185	-	309,185
19	Energy efficiency rider	44,184,056	(44,184,056)	-	YES	-	-		-	-	-
20	Miscellaneous	1,769	-	1,769	YES	-	-		1,769	-	1,769
21	Total other electric revenue	59,916,397	(44,184,056)	15,732,341		2,594,345	2,594,345		18,326,686	-	18,326,686
22	Total other operating revenues	$ 84,590,355	$ (42,397,490)	$ 42,192,865		$ 1,577,758	$ 1,577,758	A	$ 43,770,623	$ -	$ 43,770,623

IDAHO POWER COMPANY
OTHER REVENUES AND EXPENSES
For Twelve Months Ended December 31, 2011

(1) Line No	(2) Program	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
	Other Revenues (Acct 415):										
1	Power Solutions	$ 310,216	$ -	$ 310,216	YES	$ -	$ -		$ 310,216	$ -	$ 310,216
2	Hydro Services	-	-	-	YES	-	-		-	-	-
3	Water Management Services	241,330	-	241,330	YES	-	-		241,330	-	241,330
4	QRE Reporting	6,351		6,351	YES	-	-		6,351	-	6,351
5	Joint Use (Pole) - Idaho	216,838	-	216,838	YES	-	-		216,838	-	216,838
6	Joint Use (Pole) - Oregon	9,880	-	9,880	YES	-	-		9,880	-	9,880
7	Total	$ 784,615	$ -	$ 784,615		$ -	$ -	**B**	$ 784,615	$ -	$ 784,615
	Other Expenses (Acct 416):										
8	Power Solutions	$ 218,579	$ -	$ 218,579	YES	$ -	$ -		$ 218,579	$ -	$ 218,579
9	Hydro Services	3,181	-	3,181	YES	-	-		3,181	-	3,181
10	Water Management Services	117,680	-	117,680	YES	-	-		117,680	-	117,680
11	QRE Reporting	1,432	-	1,432	YES	-	-		1,432	-	1,432
12	Joint Use - Idaho	268,473	-	268,473	YES	-	-		268,473	-	268,473
13	Joint Use - Oregon	4,810	-	4,810	YES	-	-		4,810	-	4,810
14	Total	$ 614,155	$ -	$ 614,155		$ -	$ -	**C**	$ 614,155	$ -	$ 614,155

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2011

(1) LINE NO	(2) FERC ACCOUNT NUMBER	(3) DESCRIPTION	(4) 2010 Actuals	(5) 2010 Adjustments	(6) 2010 Base	(7) Forecast Methodology 2010 Base	(8) Forecast Methodology Other	(9) Forecast Adjustment	Ref No	(10) 2011 Unadjusted Test Year	(11) Annualizing	(12) 2011 Test Year
		Power production expenses:										
		Steam power generation -										
		Operation -										
1	500	Oper and supv engineering	$ 1,888,571	$ -	$ 1,888,571		$ 290,346	$ 290,346		$ 2,178,917	$ 9,936	$ 2,188,853
2	501	Fuel	-	-	-		-	-		-	-	-
3	502	Steam expenses	7,337,561	-	7,337,561		1,280,002	1,280,002		8,617,563	-	8,617,563
4	505	Electric expenses	2,140,193	-	2,140,193		373,346	373,346		2,513,539	-	2,513,539
5	506	Misc steam power expenses	9,797,756	(64,325)	9,733,431		1,705,192	1,705,192		11,438,623	1,021	11,439,644
6	507	Rents	229,316	-	229,316		40,002	40,002		269,318	-	269,318
7		Total operation	21,393,397	(64,325)	21,329,072		3,688,888	3,688,888		25,017,960	10,957	25,028,917
		Maintenance -										
8	510	Main supv and engineering	2,292,767	-	2,292,767		399,962	399,962		2,692,729	-	2,692,729
9	511	Main of structures	309,374	-	309,374		53,969	53,969		363,343	-	363,343
10	512	Main of boiler plant	16,067,832	-	16,067,832		2,802,957	2,802,957		18,870,789	-	18,870,789
11	513	Main of electric plant	3,915,290	-	3,915,290		683,004	683,004		4,598,294	-	4,598,294
12	514	Main of misc steam plant	3,753,015	-	3,753,015		654,696	654,696		4,407,711	-	4,407,711
13		Total maintenance	26,338,278	-	26,338,278		4,594,588	4,594,588		30,932,866	-	30,932,866
14		Total steam power generation	47,731,675	(64,325)	47,667,350		8,283,476	8,283,476		55,950,826	10,957	55,961,783
		Hydraulic power generation -										
		Operation -										
15	535	Oper supv and engineering	5,362,099	(66)	5,362,033		190,700	190,700		5,552,733	163,743	5,716,476
16	536	Water for power	7,322,751	(22)	7,322,729		243,349	243,349		7,566,078	22,062	7,588,140
17	537	Hydraulic expenses	10,671,807	(2,500)	10,669,307		1,099,261	1,099,261		11,768,568	184,740	11,953,308
18	538	Electric expenses	1,565,842	-	1,565,842		55,419	55,419		1,621,261	44,866	1,666,127
19	539	Misc hydro pwr gen exp	2,895,723	(351)	2,895,372		101,775	101,775		2,997,147	74,311	3,071,458
20	540	Rents	406,432	-	406,432		13,404	13,404		419,836	-	419,836
21		Total operation	28,224,654	(2,939)	28,221,715		1,703,908	1,703,908		29,925,623	489,722	30,415,345
		Maintenance -										
22	541	Main supv and engineering	1,967,876	-	1,967,876		70,356	70,356		2,038,232	64,589	2,102,821
23	542	Main of structures	1,155,653	-	1,155,653		40,462	40,462		1,196,115	28,310	1,224,425
24	543	Main of res,dams,waterwys	1,368,191	-	1,368,191		47,243	47,243		1,415,434	25,016	1,440,450
25	544	Main of electric plant	3,177,811	-	3,177,811		111,429	111,429		3,289,240	78,705	3,367,945
26	545	Main of misc hydro plant	3,029,473	-	3,029,473		106,310	106,310		3,135,783	76,527	3,212,310
27		Total maintenance	10,699,004	-	10,699,004		375,800	375,800		11,074,804	273,147	11,347,951
28		Total hydraulic power generation	38,923,658	(2,939)	38,920,719		2,079,708	2,079,708		41,000,427	762,869	41,763,296
		Other power generation -										
		Operation -										
29	546	Oper supv and engineering	328,417	-	328,417		11,785	11,785		340,202	11,348	351,550
30	547.000	Fuel - Salmon diesel	14,672	-	14,672		-	-		14,672	-	14,672
31	547	Fuel	-	-	-		-	-		-	-	-
32	548	Generation expenses	448,744	-	448,744		15,888	15,888		464,632	12,967	477,599
33	549	Misc other pwr gen exp	450,180	-	450,180		15,911	15,911		466,091	12,784	478,875
34	550	Rents	-	-	-		-	-		-	-	-
35		Total operation	1,242,013	-	1,242,013		43,584	43,584		1,285,597	37,099	1,322,696

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2011

(1) LINE NO	(2) FERC ACCOUNT NUMBER	(3) DESCRIPTION	(4) 2010 Actuals	(5) 2010 Adjustments	(6) 2010 Base	(7) Forecast Methodology 2010 Base	(8) Forecast Methodology Other	(9) Forecast Adjustment	Ref No	(10) 2011 Unadjusted Test Year	(11) Annualizing	(12) 2011 Test Year
		Other power generation - (continued)										
		Maintenance -										
1	551	Main supv and engineering	$ 43	$ -	$ 43		$ 1	$ 1		$ 44	$ -	$ 44
2	552	Main of structures	182,043	-	182,043		6,433	6,433		188,476	5,060	193,536
3	553	Main of gen and elec plt	118,533	-	118,533		4,209	4,209		122,742	3,509	126,251
4	554	Main misc oth pwr gen plt	1,077,264	-	1,077,264		1,294,436	1,294,436		2,371,700	14,054	2,385,754
							-					
5		Total maintenance	1,377,883	-	1,377,883		1,305,079	1,305,079		2,682,962	22,623	2,705,585
6		Total other power generation	2,619,896	-	2,619,896		1,348,663	1,348,663		3,968,559	59,722	4,028,281
		Other power supply expenses -										
7	555.050	Purchased power - transmission losses	1,006,538	-	1,006,538		359,462	359,462		1,366,000	-	1,366,000
8	555	Purchased power	-	-	-		-	-		-	-	-
9	556	System cont and load disp	160	-	160		5	5		165	-	165
10	557	Other expenses - other power production	2,569,334	-	2,569,334		91,215	91,215		2,660,549	77,912	2,738,461
11	557	Other expenses - PCA, EPC and PCAM	-	-	-		-	-		-	-	-
12		Total other power supply expenses	3,576,032	-	3,576,032		450,682	450,682		4,026,714	77,912	4,104,626
13		Total power production expenses	92,851,261	(67,264)	92,783,997		12,162,529	12,162,529		104,946,526	911,460	105,857,986

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2011

(1) LINE NO	(2) FERC ACCOUNT NUMBER	(3) DESCRIPTION	(4) 2010 Actuals	(5) 2010 Adjustments	(6) 2010 Base	(7) Forecast Methodology 2010 Base	(8) Forecast Methodology Other	(9) Forecast Adjustment	Ref No	(10) 2011 Unadjusted Test Year	(11) Annualizing	(12) 2011 Test Year
	Transmission expenses:											
	Operation -											
1	560	Oper supv and engineering	$ 2,992,955	$ (130)	$ 2,992,825		$ 104,884	$ 104,884		$ 3,097,709	$ 74,228	$ 3,171,937
2	561	Load dispatching	2,953,094	(76)	2,953,018		105,999	105,999		3,059,017	103,127	3,162,144
3	562	Station expenses	1,987,214	-	1,987,214		70,229	70,229		2,057,443	55,632	2,113,075
4	563	Overhead line expenses	660,035	-	660,035		2,386,852	2,386,852		3,046,887	12,886	3,059,773
5	564	Underground line expenses	-	-	-		-	-		-	-	-
6	565	Trans of elec by others	5,918,507	-	5,918,507		2,060,093	2,060,093		7,978,600	-	7,978,600
7	566	Misc trans expenses	336,835	-	336,835		11,205	11,205		348,040	1,179	349,219
8	567	Rents	1,569,168	-	1,569,168		612,921	612,921		2,182,089	-	2,182,089
9		Total operation	16,417,808	(206)	16,417,602		5,352,183	5,352,183		21,769,785	247,052	22,016,837
	Maintenance -											
10	568	Main supv and engineering	540,340	-	540,340		18,248	18,248		558,588	5,065	563,653
11	569	Main of structures	419,219	-	419,219		14,897	14,897		434,116	12,604	446,720
12	570	Main of station equip	3,447,662	(9)	3,447,653		120,091	120,091		3,567,744	76,698	3,644,442
13	571	Main of overhead lines	2,781,256	(11)	2,781,245		94,398	94,398		2,875,643	33,042	2,908,685
14	573	Main of misc trans plant	(40)	-	(40)		(2)	(2)		(42)	-	(42)
15		Total maintenance	7,188,437	(20)	7,188,417		247,632	247,632		7,436,049	127,409	7,563,458
16		Total transmission expenses	23,606,245	(226)	23,606,019		5,599,815	5,599,815		29,205,834	374,461	29,580,295
	Distribution expenses:											
	Operation -											
17	580	Oper supv and engineering	3,713,391	(1,162)	3,712,229		132,086	132,086		3,844,315	111,849	3,956,164
18	581	Load dispatching	3,419,960	-	3,419,960		122,808	122,808		3,542,768	116,327	3,659,095
19	582	Station expenses	1,277,818	(100)	1,277,718		44,913	44,913		1,322,631	33,282	1,355,913
20	583	Overhead line expenses	3,029,340	(74)	3,029,266		107,642	107,642		3,136,908	97,101	3,234,009
21	584	Underground line expenses	1,792,342	(71)	1,792,271		61,166	61,166		1,853,437	25,348	1,878,785
22	585	St light and sgnl sys exp	79,537	-	79,537		2,780	2,780		82,317	2,496	84,813
23	586	Meter expenses	4,219,271	(35)	4,219,236		25,493	25,493		4,244,729	-	4,244,729
24	587	Customer install expenses	1,521,427	(55)	1,521,372		53,651	53,651		1,575,023	41,458	1,616,481
25	588	Misc distribution exp	5,004,179	(605)	5,003,574		175,396	175,396		5,178,970	122,370	5,301,340
26	589	Rents	440,787	-	440,787		150,324	150,324		591,111	4	591,115
27		Total operation	24,498,052	(2,102)	24,495,950		876,259	876,259		25,372,209	550,235	25,922,444
	Maintenance -											
28	590	Main supv and engineering	371,979	-	371,979		13,294	13,294		385,273	12,016	397,289
29	591	Main of structures	(11,385)	-	(11,385)		(376)	(376)		(11,761)	-	(11,761)
30	592	Main of station equip	3,774,723	(113)	3,774,610		131,767	131,767		3,906,377	86,662	3,993,039
31	593	Main of overhead lines	14,297,636	(7,433)	14,290,203		489,037	489,037		14,779,240	202,962	14,982,202
32	594	Main of underground lines	1,003,404	-	1,003,404		35,257	35,257		1,038,661	25,533	1,064,194
33	595	Main of line transformers	448,157	-	448,157		14,863	14,863		463,020	982	464,002
34	596	Main of st lght-sgnl sys	587,953	-	587,953		20,401	20,401		608,354	12,945	621,299
35	597	Main of meters	700,080	-	700,080		3,933	3,933		704,013	-	704,013
36	598	Main of misc dist plant	137,583	-	137,583		4,833	4,833		142,416	4,239	146,655
37		Total maintenance	21,310,130	(7,546)	21,302,584		713,009	713,009		22,015,593	345,339	22,360,932
38		Total distribution expenses	45,808,182	(9,648)	45,798,534		1,589,268	1,589,268		47,387,802	895,574	48,283,376

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2011

(1) LINE NO	(2) FERC ACCOUNT NUMBER	(3) DESCRIPTION	(4) 2010 Actuals	(5) 2010 Adjustments	(6) 2010 Base	(7) Forecast Methodology 2010 Base	(8) Forecast Methodology Other	(9) Forecast Adjustment	Ref No	(10) 2011 Unadjusted Test Year	(11) Annualizing	(12) 2011 Test Year
	Customer accounts expenses:											
	Operation -											
1	901	Supervision	$ 410,702	$ (103)	$ 410,599		$ 14,722	$ 14,722		$ 425,321	$ 14,229	$ 439,550
2	902	Meter reading expenses	4,026,937	-	4,026,937		(1,833,435)	(1,833,435)		2,193,502	-	2,193,502
3	903	Cust records - collect exp	12,988,730	(69)	12,988,661		450,982	450,982		13,439,643	273,279	13,712,922
4	904	Uncollectible accounts	4,638,855	-	4,638,855		-	-		4,638,855	-	4,638,855
5	905	Misc customer accts exp	342	-	342		12	12		354	-	354
6		Total customer accounts expenses	22,065,566	(172)	22,065,394		(1,367,719)	(1,367,719)		20,697,675	287,508	20,985,183
	Customer service and informational expenses:											
	Operation -											
7	907	Supervision	352,778	(244)	352,534		12,606	12,606		365,140	11,052	376,192
8	908	Customer assistance exp	7,775,793	(3,127)	7,772,666		(1,352,887)	(1,352,887)		6,419,779	143,730	6,563,509
9	908	Energy efficiency rider - Idaho	42,479,689	(42,479,689)	-		-	-		-	-	-
10	908	Energy efficiency rider - Oregon	1,704,367	(1,704,367)	-		-	-		-	-	-
11	909	Info and instruct adv exp	31,517	-	31,517		1,040	1,040		32,557	-	32,557
12	910	Misc cust svc and inf exp	864,003	(329)	863,674		30,207	30,207		893,881	20,117	913,998
13	912	Demo and selling exp	-	-	-		-	-		-	-	-
14		Total customer service and informational expenses	53,208,147	(44,187,756)	9,020,391		(1,309,034)	(1,309,034)		7,711,357	174,899	7,886,256
	Administrative and general expenses:											
	Operation -											
15	920	Admin and gen salaries	47,261,758	(89)	47,261,669		1,703,947	1,703,947		48,965,616	1,618,018	50,583,634
16	920	Incentive	16,398,839	(16,398,839)	-		6,680,748	6,680,748		6,680,748	-	6,680,748
17	921	Office supplies and exp	13,613,991	(17,258)	13,596,733		1,300,867	1,300,867		14,897,600	7,681	14,905,281
18	922	Admin exp transf - cr	(27,799,634)	-	(27,799,634)		(998,665)	(998,665)		(28,798,299)	-	(28,798,299)
19	923	Outside services employed	7,210,630	(7,395)	7,203,235		237,808	237,808		7,441,043	-	7,441,043
20	924	Property insurance	3,329,577	-	3,329,577		5,031	5,031		3,334,608	21,166	3,355,774
21	925	Injuries and damages	5,668,380	-	5,668,380		187,461	187,461		5,855,841	6,440	5,862,281
22	926	Emp pensions and benefits	25,926,077	(1,027)	25,925,050		618,379	618,379		26,543,429	-	26,543,429
23	926.203	Emp pensions and benefits - Oregon	884,236	-	884,236		8,788	8,788		893,024	-	893,024
24	926.204	Emp pensions and benefits - Idaho	3,159,800	-	3,159,800		13,993,913	13,993,913		17,153,713	-	17,153,713
25	926.205	Emp pensions and benefits - FERC	60,986	-	60,986		129,964	129,964		190,950	-	190,950
26	927	Franchise requirements	2,549	-	2,549		84	84		2,633	-	2,633
27	928	Reg commission expenses	3,797,837	(5,748)	3,792,089		440,932	440,932		4,233,021	-	4,233,021
28	929	Duplicate charges - cr	-	-	-		-	-		-	-	-
29	930.1	General advertising exp	417,950	(417,950)	-		-	-		-	-	-
30	930.2	Misc general expenses	3,826,102	(181,010)	3,645,092		140,403	140,403		3,785,495	5,253	3,790,748
31	931	Rents	12,600	-	12,600		12,588	12,588		25,188	-	25,188
32		Total operation	103,771,678	(17,029,316)	86,742,362		24,462,248	24,462,248		111,204,610	1,658,558	112,863,168
	Maintenance -											
36	935	Main of general plant	4,182,611	(16)	4,182,595		145,593	145,593		4,328,188	42,431	4,370,619
34		Total maintenance	4,182,611	(16)	4,182,595		145,593	145,593		4,328,188	42,431	4,370,619
35		Total administrative and general expenses	107,954,289	(17,029,332)	90,924,957		24,607,841	24,607,841		115,532,798	1,700,989	117,233,787
36		Total electric operation and maintenance expenses	$ 345,493,690	$ (61,294,398)	$ 284,199,292		$ 41,282,700	$ 41,282,700	D	$ 325,481,992	$ 4,344,891	$ 329,826,883

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
PROPERTY INSURANCE - ACCOUNT 924
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2011		
Line No	Description	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
	Production - steam:										
1	Bridger plant	$ 408,383	$ -	$ 408,383		$ -	$ -		$ 408,383	$ -	$ 408,383
2	Boardman plant	49,753	-	49,753		-	-		49,753	-	49,753
3	Valmy plant	351,701	-	351,701		-	-		351,701	-	351,701
4	Total production - steam	809,837	-	809,837		-	-		809,837	-	809,837
	All risk:										
5	Blanket fidelity bond	63,170	-	63,170		-	-		63,170	-	63,170
6	Property "all risk"	2,192,332	-	2,192,332		-	-		2,192,332	12,008	2,204,340
7	Other miscellaneous	264,238	-	264,238		5,031	5,031		269,269	9,158	278,427
8	Total all risk	2,519,740	-	2,519,740		5,031	5,031		2,524,771	21,166	2,545,937
9	Total property insurance	$ 3,329,577	$ -	$ 3,329,577		$ 5,031	$ 5,031	D	$ 3,334,608	$ 21,166	$ 3,355,774

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
REGULATORY COMMISSION EXPENSES - ACCOUNT 928
For Twelve Months Ended December 31, 2011

(1) Line No	(2) Description	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
	FERC administrative assessments and securities (928.101)										
1	Capacity	$ 1,661,164	$ -	$ 1,661,164		$ 131,221	$ 131,221		$ 1,792,385	$ -	$ 1,792,385
2	Generation	706,272	-	706,272		55,791	55,791		762,063	-	762,063
3	Ferc Order #472 - Sales for resale	466,188	-	466,188		36,825	36,825		503,013	-	503,013
4	Miscellaneous Other	539,362	-	539,362		42,607	42,607		581,969	-	581,969
5	Total (928.101)	3,372,986	-	3,372,986		266,444	266,444		3,639,430	-	3,639,430
6	FERC - Rate Case (928.102)	704	-	704		23	23		727	-	727
7	FERC - Oregon Hydro (928.104)	158,506	-	158,506		5,227	5,227		163,733	-	163,733
8	Total FERC expense	3,532,196	-	3,532,196		271,694	271,694		3,803,890	-	3,803,890
	Idaho Public Utilities Commission expense:										
9	Rate case (928.202)	1,024	-	1,024		54,349	54,349		55,373	-	55,373
10	Other (928.203)	31,419	(5,748)	25,671		42,077	42,077		67,748	-	67,748
11	Total IPUC expense	32,443	(5,748)	26,695		96,426	96,426		123,121	-	123,121
	Oregon Public Utility Commission expense:										
12	Filing Fees (928.301)	-	-	-		-	-		-	-	-
13	Rate case (928.302)	6,532	-	6,532		216	216		6,748	-	6,748
14	Other (928.303)	226,666	-	226,666		72,596	72,596		299,262	-	299,262
15	Total OPUC expense	233,198	-	233,198		72,812	72,812		306,010	-	306,010
	Nevada Public Service Commission expense:										
16	Other (928.403)	-	-	-		-	-		-	-	-
17	Total NPSC expense	-	-	-		-	-		-	-	-
18	Total regulatory commission expenses	$ 3,797,837	$ (5,748)	$ 3,792,089		$ 440,932	$ 440,932	D	$ 4,233,021	$ -	$ 4,233,021

IDAHO POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSE
For Twelve Months Ended December 31, 2011

(1) Line No	(2) Description	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
	Accounts 403 and 404:										
1	Amortization expense	$ 6,857,301	$ -	$ 6,857,301		$ 184,774	$ 184,774		$ 7,042,075	$ 189,455	$ 7,231,530
2	Depreciation expense	109,099,197	-	109,099,197		4,789,543	4,789,543		113,888,740	2,225,161	116,113,901
3	Total	$ 115,956,498	$ -	$ 115,956,498		$ 4,974,317	$ 4,974,317	E	$ 120,930,815	$ 2,414,616	$ 123,345,431

IDAHO POWER COMPANY
ELECTRIC PLANT/REGULATORY ASSETS - AMORT.,ADJUST.,GAINS & LOSSES
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)	(11)	(12)
						Forecast Methodology				2011		
Line No		Description	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
1	406	Amortization of electric plant acquisition adjustment - Prairie Power..	$ (22,723)	$ -	$ (22,723)		$ -	$ -		$ (22,723)	$ -	$ (22,723)
2		Total...	$ (22,723)	$ -	$ (22,723)		$ -	$ -	F	$ (22,723)	$ -	$ (22,723)

IDAHO POWER COMPANY
REGULATORY DEBITS AND CREDITS
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2011		
Line No	Description	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
	Regulatory Debits/Credits (Acct 407.3/407.4):										
1	Amortization of Oregon deferred pension..........................	$ 21,955	$ -	$ 21,955		$ 5,802	$ 5,802		$ 27,757	$ -	$ 27,757
2	Total...	$ 21,955	$ -	$ 21,955		$ 5,802	$ 5,802	**G**	$ 27,757	$ -	$ 27,757

IDAHO POWER COMPANY
TAXES OTHER THAN INCOME TAXES
For Twelve Months Ended December 31, 2011

(1) Line No	(2) Description	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
	Federal taxes:										
1	Unemployment	$ 120,285	$ (120,285)	$ -	YES	$ -	$ -		$ -	$ -	$ -
2	Social Security	12,457,819	(12,457,819)	-	YES	-	-		-	-	-
3	Total federal taxes	12,578,104	(12,578,104)	-		-	-		-	-	-
	State, county and local taxes:										
	Real and personal property:										
4	Idaho	14,864,080	-	14,864,080		2,655,853	2,655,853		17,519,933	-	17,519,933
5	Oregon	2,228,127	-	2,228,127		162,507	162,507		2,390,634	-	2,390,634
6	Montana	210,443	-	210,443		14,557	14,557		225,000	-	225,000
7	Wyoming	1,271,134	-	1,271,134		228,866	228,866		1,500,000	-	1,500,000
8	Nevada	1,108,774	-	1,108,774		(15,571)	(15,571)		1,093,203	-	1,093,203
9	Shoshone-Bannock	70,533	-	70,533		1,058	1,058		71,591	-	71,591
10	Total real and personal property	19,753,091	-	19,753,091		3,047,270	3,047,270		22,800,361	-	22,800,361
11	Kilowatt-hour tax - Idaho	1,645,778	-	1,645,778		390,851	390,851		2,036,629	-	2,036,629
	Licenses:										
12	Wyoming	3,950	-	3,950		730	730		4,680	-	4,680
13	Shoshone-Bannock	300	-	300		(150)	(150)		150	-	150
14	Total licenses	4,250	-	4,250		580	580		4,830	-	4,830
	Regulatory commission:										
15	Idaho	1,837,184	-	1,837,184	YES	-	-		1,837,184	-	1,837,184
16	Oregon	92,603	-	92,603		48,339	48,339		140,942	-	140,942
17	Total regulatory commission	1,929,787	-	1,929,787		48,339	48,339		1,978,126	-	1,978,126
	Franchise:										
18	Oregon total franchise	713,129	-	713,129		(32,970)	(32,970)		680,159	-	680,159
										-	
19	Unemployment - total state	1,108,246	(1,108,246)	-	YES	-	-		-	-	-
20	Total state, county and local taxes	25,154,281	(1,108,246)	24,046,035		3,454,070	3,454,070		27,500,105	-	27,500,105
21	Total other taxes	37,732,385	(13,686,350)	24,046,035		3,454,070	3,454,070		27,500,105	-	27,500,105
22	Less: State & Fed P/R Loading Reversal	(13,686,350)	13,686,350	-		-	-		-	-	-
23	Net other taxes	$ 24,046,035	$ -	$ 24,046,035		$ 3,454,070	$ 3,454,070	H	$ 27,500,105	$ -	$ 27,500,105

IDAHO POWER COMPANY
STATEMENT OF INCOME
FOR IDAHO ENERGY RESOURCES COMPANY
For Twelve Months Ended December 31, 2011

(1) Line No	(2) Description	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
	Income:										
1	Bridger Coal Company - joint venture	$ 11,280,852	$ -	$ 11,280,852		$ (1,080,852)	$ (1,080,852)		$ 10,200,000	$ -	$ 10,200,000
2	Bridger Coal Company - overriding royalties	66,342	-	66,342		7,644	7,644		73,986	-	73,986
3	Interest and dividend income	189,847	-	189,847		(189,847)	(189,847)		-	-	-
4	Taxes Other than Income Taxes	-	-	-		-	-		-	-	-
5	Total income	11,537,041	-	11,537,041		(1,263,055)	(1,263,055)		10,273,986	-	10,273,986
	Expenses:										
6	Operation expense	66,551	-	66,551		7,437	7,437		73,988	-	73,988
7	Income taxes	3,879,289	-	3,879,289		(341,975)	(341,975)		3,537,314	-	3,537,314
8	Provision for deferred income taxes	-	-	-		-	-		-	-	-
9	Intercompany interest expense	44,869	-	44,869		48,519	48,519		93,388	-	93,388
10	Interest expense	-	-	-		-	-		-	-	-
11	Total expenses	3,990,709	-	3,990,709		(286,019)	(286,019)		3,704,690	-	3,704,690
12	Net income from operations	7,546,332	-	7,546,332		(977,036)	(977,036)		6,569,296	-	6,569,296
13	Add: Interest expense from notes payable to parent (Net of Tax)	29,165	-	29,165		31,537	31,537		60,702	-	60,702
14	Net income (earnings to Idaho Power Company)	$ 7,575,497	$ -	$ 7,575,497		$ (945,499)	$ (945,499)		$ 6,629,998	$ -	$ 6,629,998

IDAHO POWER COMPANY
ELECTRIC PLANT IN SERVICE (Excluding ARO Entries)
For The Thirteen Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2011		
Line No	Month	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
1	December, 2009	$ 4,156,814,543	$ -	$ 4,156,814,543		$ 171,590,192	$ 171,590,192		$ 4,328,404,735	$ -	$ 4,328,404,735
2	January, 2010	4,157,393,363	-	4,157,393,363		179,893,941	179,893,941		4,337,287,304	-	4,337,287,304
3	February	4,166,176,103	-	4,166,176,103		178,642,613	178,642,613		4,344,818,716	-	4,344,818,716
4	March	4,173,719,800	-	4,173,719,800		183,780,037	183,780,037		4,357,499,837	-	4,357,499,837
5	April	4,173,092,585	-	4,173,092,585		193,221,544	193,221,544		4,366,314,129	-	4,366,314,129
6	May	4,187,044,366	-	4,187,044,366		186,692,379	186,692,379		4,373,736,745	-	4,373,736,745
7	June	4,208,744,445	-	4,208,744,445		195,910,323	195,910,323		4,404,654,768	-	4,404,654,768
8	July	4,276,133,715	-	4,276,133,715		142,329,428	142,329,428		4,418,463,143	-	4,418,463,143
9	August	4,281,315,297	-	4,281,315,297		144,269,264	144,269,264		4,425,584,561	-	4,425,584,561
10	September	4,288,337,511	-	4,288,337,511		149,514,697	149,514,697		4,437,852,208	-	4,437,852,208
11	October	4,300,535,064	-	4,300,535,064		145,631,296	145,631,296		4,446,166,360	-	4,446,166,360
12	November	4,310,090,611	-	4,310,090,611		147,047,274	147,047,274		4,457,137,885	-	4,457,137,885
13	December	4,328,404,735	-	4,328,404,735		137,815,481	137,815,481		4,466,220,216	-	4,466,220,216
14	Average	$ 4,231,369,395	$ -	$ 4,231,369,395		$ 165,872,190	$ 165,872,190	J	$ 4,397,241,585	$ -	$ 4,397,241,585

IDAHO POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION (Excluding ARO Entries)
For The Thirteen Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2011		
Line No	Month	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
1	December, 2009	$ 1,690,985,018	$ -	$ 1,690,985,018		$ 57,281,530	$ 57,281,530		$ 1,748,266,548	$ -	$ 1,748,266,548
2	January, 2010	1,698,964,538	-	1,698,964,538		56,700,560	56,700,560		1,755,665,098	-	1,755,665,098
3	February	1,706,470,899	-	1,706,470,899		57,251,316	57,251,316		1,763,722,215	-	1,763,722,215
4	March	1,703,526,938	-	1,703,526,938		67,292,711	67,292,711		1,770,819,649	-	1,770,819,649
5	April	1,711,432,889	-	1,711,432,889		68,047,828	68,047,828		1,779,480,717	-	1,779,480,717
6	May	1,719,152,114	-	1,719,152,114		69,071,412	69,071,412		1,788,223,526	-	1,788,223,526
7	June	1,723,610,925	-	1,723,610,925		63,847,320	63,847,320		1,787,458,245	-	1,787,458,245
8	July	1,732,507,865	-	1,732,507,865		57,282,575	57,282,575		1,789,790,440	-	1,789,790,440
9	August	1,737,927,039	-	1,737,927,039		60,348,446	60,348,446		1,798,275,485	-	1,798,275,485
10	September	1,740,051,390	-	1,740,051,390		65,390,714	65,390,714		1,805,442,104	-	1,805,442,104
11	October	1,749,452,287	-	1,749,452,287		64,831,894	64,831,894		1,814,284,181	-	1,814,284,181
12	November	1,756,647,651	-	1,756,647,651		65,818,973	65,818,973		1,822,466,624	-	1,822,466,624
13	December	1,748,266,548	-	1,748,266,548		75,425,552	75,425,552		1,823,692,100	-	1,823,692,100
14	Average	$ 1,724,538,162	$ -	$ 1,724,538,162		$ 63,737,756	$ 63,737,756	K	$ 1,788,275,918	$ -	$ 1,788,275,918

IDAHO POWER COMPANY
ACCUMULATED PROVISION FOR AMORTIZATION (Excluding ARO Entries)
OF ELECTRIC UTILITY PLANT
For The Thirteen Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2011		
Line No	Month	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Normalizing	2011 Test Year
1	December, 2009	$ 21,016,304	$ -	$ 21,016,304		$ 320,750	$ 320,750		$ 21,337,054	$ -	$ 21,337,054
2	January, 2010	15,125,898	-	15,125,898		2,908,400	2,908,400		18,034,298	-	18,034,298
3	February	15,663,602	-	15,663,602		2,929,379	2,929,379		18,592,981	-	18,592,981
4	March	16,200,021	-	16,200,021		2,953,169	2,953,169		19,153,190	-	19,153,190
5	April	16,692,826	-	16,692,826		3,030,713	3,030,713		19,723,539	-	19,723,539
6	May	17,288,012	-	17,288,012		3,009,056	3,009,056		20,297,068	-	20,297,068
7	June	17,838,478	-	17,838,478		3,035,303	3,035,303		20,873,781	-	20,873,781
8	July	18,418,420	-	18,418,420		3,045,798	3,045,798		21,464,218	-	21,464,218
9	August	18,999,998	-	18,999,998		3,056,650	3,056,650		22,056,648	-	22,056,648
10	September	19,583,801	-	19,583,801		3,067,976	3,067,976		22,651,777	-	22,651,777
11	October	20,167,606	-	20,167,606		3,084,466	3,084,466		23,252,072	-	23,252,072
12	November	20,752,330	-	20,752,330		3,100,481	3,100,481		23,852,811	-	23,852,811
13	December	21,337,054	-	21,337,054		3,118,385	3,118,385		24,455,439	-	24,455,439
14	Average	$ 18,391,104	$ -	$ 18,391,104		$ 2,820,040	$ 2,820,040	L	$ 21,211,144	$ -	$ 21,211,144

IDAHO POWER COMPANY
MATERIALS AND SUPPLIES
For The Thirteen Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)
		2010 Actuals					Forecast Methodology				2011		
Line No	Month	Account 154	Account 163	Total	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
1	December, 2009	$ 43,342,060	$ 4,711,966	$ 48,054,026	$ -	$ 48,054,026		$ (2,453,105)	$ (2,453,105)		$ 45,600,921	$ -	$ 45,600,921
2	January, 2010	43,921,795	4,787,486	48,709,281	-	48,709,281		(2,826,338)	(2,826,338)		45,882,943	-	45,882,943
3	February	43,770,175	5,619,898	49,390,073	-	49,390,073		(3,731,364)	(3,731,364)		45,658,709	-	45,658,709
4	March	43,124,506	4,410,396	47,534,902	-	47,534,902		(1,747,901)	(1,747,901)		45,787,001	-	45,787,001
5	April	42,740,511	4,337,104	47,077,615	-	47,077,615		(1,162,321)	(1,162,321)		45,915,294	-	45,915,294
6	May	43,088,560	4,254,186	47,342,746	-	47,342,746		(1,299,160)	(1,299,160)		46,043,586	-	46,043,586
7	June	43,017,520	4,418,433	47,435,953	-	47,435,953		(1,264,074)	(1,264,074)		46,171,879	-	46,171,879
8	July	41,900,492	4,064,137	45,964,629	-	45,964,629		335,542	335,542		46,300,171	-	46,300,171
9	August	42,146,520	3,943,399	46,089,919	-	46,089,919		338,545	338,545		46,428,464	-	46,428,464
10	September	41,479,326	3,851,381	45,330,707	-	45,330,707		1,226,049	1,226,049		46,556,756	-	46,556,756
11	October	42,278,796	3,638,161	45,916,957	-	45,916,957		851,425	851,425		46,768,382	-	46,768,382
12	November	41,862,927	3,518,161	45,381,088	-	45,381,088		1,598,920	1,598,920		46,980,008	-	46,980,008
13	December	42,221,176	3,379,745	45,600,921	-	45,600,921		1,590,713	1,590,713		47,191,634	-	47,191,634
14	Average	$ 42,684,182	$ 4,225,727	$ 46,909,909	$ -	$ 46,909,909		$ (657,159)	$ (657,159)	M	$ 46,252,750	$ -	$ 46,252,750

IDAHO POWER COMPANY
OTHER DEFERRED PROGRAMS
At December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2011		
Line No	Description	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
	Idaho Public Utilities Commission:										
	Account 186										
1	American Falls Bond Refinancing - (IPUC Order 25880)	$ 886,145	$ -	$ 886,145		$ (62,552)	$ (62,552)		$ 823,593	$ -	$ 823,593
	Account 182										
2	Intervenor Funding - CAPAI (IPUC Order 30722)	10,572	-	10,572		(10,572)	(10,572)		-	-	-
3	Intervenor Funding - Idaho Irrigators (IPUC Order 30722)	35,480	-	35,480		(35,480)	(35,480)		-	-	-
	Oregon Public Utilities Commission:										
4	Citizen Utility Board 2010 Fund Grant - (OPUC Order 10-406)	30,100	-	30,100		(30,100)	(30,100)		-	-	-
5	SFAS 87 Capitalized Pension Costs - (OPUC Order 10-064)	939,890	-	939,890		383,271	383,271		1,323,161	-	1,323,161
6	Grid West Loans - (OPUC Order 06-483)	59,128	-	59,128		(14,191)	(14,191)		44,937	-	44,937
	Federal Energy Regulatory Commission:										
7	Grid West Loans	195,524	-	195,524		(83,796)	(83,796)		111,728	-	111,728
8	Total	$ 2,156,839	$ -	$ 2,156,839		$ 146,580	$ 146,580	N	$ 2,303,419	$ -	$ 2,303,419

IDAHO POWER COMPANY
2011 RATE CASE
ACCUMULATED DEFERRED INCOME TAXES

	Balance Dec 31, 2010	2011 Change	Balance Dec 31, 2011	Average 2010-2011
ACCOUNT 190 - ACCUM DEF INC TAXES:				
004003-CONSTRUCTION ADV-252	7,061,284	(1,884,474)	5,176,810	6,119,047
004022-FERC CREDIT OFA-ACCT 254	182,023	(182,023)	0	91,012
005010-SFAS 112-POST-EMPLY BEN 182/253	1,504,637	0	1,504,637	1,504,637
005033-NONVEBA PEN&BEN-Acct 228	414,233	0	414,233	414,233
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228	1,855,362	(451,156)	1,404,206	1,629,784
005053-FAS 123R-STOCK BASED COMPENSATION	2,496,071	0	2,496,071	2,496,071
005061-PENSION EXPENSE-OREGON	817,275	359,980	1,177,255	997,265
005531-RATE CASE DISALLOWANCES-REVERSE AMORT	2,765,194	(115,840)	2,649,354	2,707,274
008001-VEBA-POST RET BNFTS-TRUST-ACCT 228	5,658,260	952,818	6,611,078	6,134,669
TOTAL 190	22,754,339	(1,320,695)	21,433,644	22,093,992
ACCOUNT 282 - ACCUM DEF INC TAXES - OTHER PROPERTY:				
LIBERALIZED DEPR - ELECTRIC PLANT	(271,486,740)	(45,400,066)	(316,886,806)	(294,186,773)
N VALMY PARTNERSHIP CAPITALIZED ITEMS	(427,766)	76,500	(351,266)	(389,516)
TOTAL 282	(271,914,506)	(45,323,566)	(317,238,072)	(294,576,289)
ACCOUNT 283 - ACCUM DEF INC TAXES - OTHER:				
004501-ROYALTY INCOME	(293,553)	0	(293,553)	(293,553)
005023-PENSION EXPENSE-IDAHO & FERC	(22,197,834)	6,819,094	(15,378,740)	(18,788,287)
005048-BONUS DEFERRAL-ACCT 232	(515)	0	(515)	(515)
005054-IPUC GRID WEST LOANS-ACCT 182	(72,888)	72,888	0	(36,444)
005055-OPUC GRID WEST LOANS-ACCT 182	(23,115)	5,547	(17,568)	(20,342)
005056-FERC GRID WEST EXP-ACCT 182	(76,441)	32,760	(43,681)	(60,061)
005057-INTERVENOR FUNDING ORDERS-ACCT 182	(47,339)	47,339	0	(23,670)
005532-DELIVERY ACCRUALS-ACCT 253	(15,266)	0	(15,266)	(15,266)
008057-REORGANIZATION COSTS-ACCT 182	(360,700)	90,176	(270,524)	(315,612)
TOTAL 283	(23,087,651)	7,067,804	(16,019,847)	(19,553,750)
TOTAL DEFERRED TAX BALANCES	**(272,247,818)**	**(39,576,457)**	**(311,824,275)**	**(292,036,047)**

Deferred Tax Expense without ITC - 410 / 411	39,576,457
ITC Deferred Tax Expense - 411.4	(470,989)
Total Deferred Tax Expense	39,105,468

IDAHO POWER COMPANY
CUSTOMER ADVANCES FOR CONSTRUCTION
For The Thirteen Months Ended December 31, 2011

(1) Line No	(2) Month	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
1	December, 2009	$ 25,180,998	$ -	$ 25,180,998		$ (6,034,061)	$ (6,034,061)		$ 19,146,937	$ -	$ 19,146,937
2	January, 2010	24,698,698	-	24,698,698		(5,799,110)	(5,799,110)		18,899,588	-	18,899,588
3	February	24,306,094	-	24,306,094		(5,939,591)	(5,939,591)		18,366,503	-	18,366,503
4	March	23,326,546	-	23,326,546		(5,298,114)	(5,298,114)		18,028,432	-	18,028,432
5	April	23,993,449	-	23,993,449		(6,311,561)	(6,311,561)		17,681,888	-	17,681,888
6	May	23,842,449	-	23,842,449		(6,420,582)	(6,420,582)		17,421,867	-	17,421,867
7	June	23,296,869	-	23,296,869		(6,147,375)	(6,147,375)		17,149,494	-	17,149,494
8	July	22,991,687	-	22,991,687		(5,860,206)	(5,860,206)		17,131,481	-	17,131,481
9	August	22,552,101	-	22,552,101		(5,820,649)	(5,820,649)		16,731,452	-	16,731,452
10	September	21,909,249	-	21,909,249		(5,507,016)	(5,507,016)		16,402,233	-	16,402,233
11	October	23,805,152	-	23,805,152		(7,796,760)	(7,796,760)		16,008,392	-	16,008,392
12	November	23,400,419	-	23,400,419		(7,597,138)	(7,597,138)		15,803,281	-	15,803,281
13	December	23,054,016	-	23,054,016		(7,425,632)	(7,425,632)		15,628,384	-	15,628,384
14	Average	$ 23,565,979	$ -	$ 23,565,979		$ (6,304,446)	$ (6,304,446)	O	$ 17,261,533	$ -	$ 17,261,533

IDAHO POWER COMPANY
IERCo - SUBSIDIARY RATE BASE COMPONENTS
For The Thirteen Months Ended December 31, 2011

(1) Line No	(2) Month	(3) 2010 Actuals Investment	(4) 2010 Actuals Advance Coal Royalties	(5) 2010 Actuals Notes Rec from Subsidiary	(6) 2010 Actuals Total	(7) 2010 Adjustments	(8) 2010 Base	(9) Forecast Methodology 2010 Base	(10) Forecast Methodology Other	(11) Forecast Adjustment	Ref No	(12) 2011 Unadjusted Test Year	(13) Annualizing	(14) 2011 Test Year
1	December, 2009.......	$ 65,015,441	$ 1,507,205	$ 18,894,101	$ 85,416,747	$ (85,531)	$ 85,331,216		$ 2,963,173	$ 2,963,173		$ 88,294,389	$ -	$ 88,294,389
2	January, 2010...........	63,973,426	1,499,561	21,095,921	86,568,908	(85,531)	86,483,377		1,169,298	1,169,298		87,652,675	-	87,652,675
3	February...................	64,975,377	1,495,220	20,747,697	87,218,294	(85,531)	87,132,763		(1,069,941)	(1,069,941)		86,062,822	-	86,062,822
4	March........................	65,361,104	1,474,739	20,579,057	87,414,900	(85,531)	87,329,369		(2,575,652)	(2,575,652)		84,753,717	-	84,753,717
5	April...........................	65,432,902	1,471,734	20,302,131	87,206,767	(85,531)	87,121,236		(102,806)	(102,806)		87,018,430	-	87,018,430
6	May...........................	66,423,016	1,460,137	21,845,196	89,728,349	(85,531)	89,642,818		(1,005,031)	(1,005,031)		88,637,787	-	88,637,787
7	June..........................	66,643,635	1,460,794	22,317,896	90,422,325	(85,531)	90,336,794		664,044	664,044		91,000,838	-	91,000,838
8	July...........................	67,829,910	1,455,791	23,423,835	92,709,536	(85,531)	92,624,005		(1,501,926)	(1,501,926)		91,122,079	-	91,122,079
9	August......................	68,522,619	1,450,728	21,129,029	91,102,376	(85,531)	91,016,845		256,183	256,183		91,273,028	-	91,273,028
10	September................	70,184,541	1,446,260	20,796,633	92,427,434	(85,531)	92,341,903		(1,072,320)	(1,072,320)		91,269,583	-	91,269,583
11	October.....................	70,410,295	1,443,426	17,899,998	89,753,719	(85,531)	89,668,188		852,399	852,399		90,520,587	-	90,520,587
12	November.................	71,235,047	1,437,825	15,032,039	87,704,911	(85,531)	87,619,380		1,722,880	1,722,880		89,342,260	-	89,342,260
13	December.................	72,561,774	1,433,219	14,384,928	88,379,921	(85,531)	88,294,390		1,703,385	1,703,385		89,997,775	-	89,997,775
14	Average.................	$ 67,582,237	$ 1,464,357	$ 19,880,651	$ 88,927,245	$ (85,531)	$ 88,841,714		$ 154,130	$ 154,130	**P**	$ 88,995,844	$ -	$ 88,995,844

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Douglas N. Jones
Deductions from Operations and Maintenance Expenses

July 29, 2011

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
GENERAL ADVERTISING EXPENSE (ACCOUNT 930.1)
For Twelve Months Ended December 31, 2011

(1) Line No	(2) Description	(3) 2010 Actuals	(4) 2010 Adjustments	(5) 2010 Base	(6) Forecast Methodology 2010 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2011 Unadjusted Test Year	(10) Annualizing	(11) 2011 Test Year
1	General Advertising Expense..	$ 417,950	$ (417,950)	$ -		$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
MEMBERSHIPS AND CONTRIBUTIONS
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			Actual				
Line No	Acct No	Organization	Contributions 100%	Memberships 33.33%	Memberships 100%	2010 Actuals	2010 Adjustments
1	537	Edison Electric Institute	$ -	$ 833	$ -	$ 833	$ (833)
2	537	Lower Boise Watershed Council	1,000	-	-	1,000	(1,000)
3	537	Treasure Valley Chapter	300	-	-	300	(300)
4	539	Hells Canyon Riders Donation	312	-	-	312	(312)
5	560	Edison Electric Institute	-	11	-	11	(11)
6	580	National Arbor Day	309	-	-	309	(309)
7	580	Donation	4	-	-	4	(4)
8	580	Magic Valley Adult Leadership, Chamber of Commerce	-	107	-	107	(107)
9	580	Chamber of Commerce Pocatello	-	217	-	217	(217)
10	582	Rimrock Community Food Bank	100	-	-	100	(100)
11	586	Rotary Club Pocatello	-	20	-	20	(20)
12	588	Chamber of Commerce Boise Metro	-	7	-	7	(7)
13	588	Rotary Club McCall	-	133	-	133	(133)
14	588	Edison Electric Institute	-	217	-	217	(217)
15	588	City Club of Boise	-	3	-	3	(3)
16	593	National Arbor Day	7,309	-	-	7,309	(7,309)
17	907	Rotary Club Pocatello	-	244	-	244	(244)
18	908	Association of Idaho Cities	-	233	-	233	(233)
19	908	Chamber of Commerce	-	10	-	10	(10)
20	908	Chamber of Commerce Boise Metro	-	127	-	127	(127)
21	908	Chamber of Commerce Mountain Home	-	17	-	17	(17)
22	908	Chamber of Commerce Homedale	-	20	-	20	(20)
23	908	Chamber of Commerce Nampa	-	210	-	210	(210)
24	908	Donation	6	-	-	6	(6)
25	908	Edison Electric Institute	-	132	-	132	(132)
26	908	Chamber of Commerce Greater Pocatello	-	17	-	17	(17)
27	908	Kiwanis Club Eagle	-	77	-	77	(77)
28	908	Kiwanis Club Les Bois	-	283	-	283	(283)
29	908	KMTV TV Ag Show Booth	925	-	-	925	(925)
30	908	Lions Club Idaho City	-	33	-	33	(33)
31	908	Lions Club Jordon Valley	-	10	-	10	(10)
32	908	Lions Club Twin Falls	-	136	-	136	(136)
33	908	Rotary Club	-	34	-	34	(34)
34	908	Rotary Club Boise	-	221	-	221	(221)
35	908	Rotary Club Boise Centennial	-	270	-	270	(270)
36	908	Rotary Club Caldwell	-	85	-	85	(85)
37	910	Donation	15	-	-	15	(15)
38	910	Rotary Club Blackfoot	-	183	-	183	(183)
39	910	Rotary Club Gate City	-	84	-	84	(84)
40	921	Association of Idaho Cities	-	47	-	47	(47)
41	921	City Club of Boise	-	30	-	30	(30)
42	921	Edison Electric Institute	-	3,575	-	3,575	(3,575)
43	921	Chamber of Commerce North Idaho Legislative	2,500	-	-	2,500	(2,500)
44	921	Idaho Watercolor Society Sponsorship	300	-	-	300	(300)
45	921	Rotary Club of Boise - Sunrise	-	164	-	164	(164)
46	921	Chamber of Commerce Boise Metro	-	17	-	17	(17)

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
MEMBERSHIPS AND CONTRIBUTIONS
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			Actual				
Line	Acct		Contributions	Memberships		2010	2010
No	No	Organization	100%	33.33%	100%	Actuals	Adjustments
47	930	American Planning Association of Idaho	500	-	-	500	(500)
48	930	Associated Tax Payers of Idaho	-	-	21,252	21,252	(21,252)
49	930	Association of Idaho Cities	-	1,083	-	1,083	(1,083)
50	930	Chamber of Commerce Baker County	-	328	-	328	(328)
51	930	Castleford Men's Club Contribution	-	-	20	20	(20)
52	930	Chamber of Commerce	-	3,445	-	3,445	(3,445)
53	930	Chamber of Commerce Idaho City	-	33	-	33	(33)
54	930	Chamber of Commerce Blackfoot	-	8	-	8	(8)
55	930	Chamber of Commerce Boise	-	4,240	-	4,240	(4,240)
56	930	Chamber of Commerce Boise Metro	-	4,363	-	4,363	(4,363)
57	930	Chamber of Commerce Caldwell	-	333	-	333	(333)
58	930	Chamber of Commerce Hailey	-	238	-	238	(238)
59	930	Chamber of Commerce Jerome	-	142	-	142	(142)
60	930	Chamber of Commerce Eagle	-	158	-	158	(158)
61	930	Chamber of Commerce Lincoln County	-	33	-	33	(33)
62	930	Chamber of Commerce Buhl	-	158	-	158	(158)
63	930	Chamber of Commerce Gem County	-	150	-	150	(150)
64	930	Chamber of Commerce Hagerman	-	83	-	83	(83)
65	930	Chamber of Commerce Idaho Falls	-	75	-	75	(75)
66	930	Chamber of Commerce Kuna	-	333	-	333	(333)
67	930	Chamber of Commerce McCall	-	332	-	332	(332)
68	930	Chamber of Commerce Meridian	-	441	-	441	(441)
69	930	Chamber of Commerce Mountain Home	-	67	-	67	(67)
70	930	Chamber of Commerce Pocatello	-	1,549	-	1,549	(1,549)
71	930	Chamber of Commerce Salmon River Valley	120	33	-	153	(153)
72	930	Chamber of Commerce Payette	-	83	-	83	(83)
73	930	Chamber of Commerce Donations/Contributions/Sponsorship	12,403	-	-	12,403	(12,403)
74	930	City Club of Boise	-	200	-	200	(200)
75	930	Economic Development Chamber of Commerce	-	100	-	100	(100)
76	930	Economic Development Contribution Star	500	-	-	500	(500)
77	930	Economic Development Contribution Caldwell	2,500	-	-	2,500	(2,500)
78	930	Edison Electric Institute	-	122,243	-	122,243	(122,243)
79	930	Lions Club Nampa	-	167	-	167	(167)
80	930	Great River Business Development	1,000	-	-	1,000	(1,000)
81	930	Salmon River Chamber Steelhead	200	-	-	200	(200)
82	930	Idaho City Managers Association	500	-	-	500	(500)
83	930	Rotary Club Gooding	-	447	-	447	(447)
84	930	Rotary Club Blue Lakes	-	279	-	279	(279)
85	930	Rotary Club Buhl	-	103	-	103	(103)
86	930	Rotary Club Hailey	-	157	-	157	(157)
87	930	Rotary Club Jerome	-	221	-	221	(221)
88	930	Rotary Club Nampa	-	96	-	96	(96)
89	930	Rotary Club Ketchum/Sun Valley	-	86	-	86	(86)
90	930	Rotary Club Twin Falls	-	208	-	208	(208)
91		Total	$ 30,803	$ 149,822	$ 21,272	$ 201,897	$ (201,897)

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)
No	Name	2010 Actuals	2010 Adjustments
1	**Darrel Anderson**		
2	Total Expenses	$ 13,733	
3	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
4	Arid Club	-	
5	EEI	(6,438)	
7	Total	7,295	
8	Payroll Percentage Allocated to IDACORP	3.20%	
9	Net IDACORP Exclusions	233	
10	Other Exclusions:		
11	Arid Club (100% Per IPUC Order 29505)	-	
13	EEI (1/3 Per IPUC Order 29505)	2,146	
14	Total Exclusions	$ 2,379	$ (2,379)
15	**Rex Blackburn**		
16	Total Expenses	$ 1,162	
17	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
18	Arid Club	-	
19	EEI	-	
20	Total	1,162	
21	Payroll Percentage Allocated to IDACORP	2.10%	
22	Net IDACORP Exclusions	24	
23	Other Exclusions:		
24	Arid Club (100% Per IPUC Order 29505)	-	
25	EEI (1/3 Per IPUC Order 29505)	-	
26	Total Exclusions	$ 24	$ (24)
27	**Naomi Crafton-Shankel**		
28	Total Expenses	$ 3,453	
29	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
30	Arid Club	-	
31	EEI	-	
32	Total	3,453	
33	Payroll Percentage Allocated to IDACORP	1.40%	
34	Net IDACORP Exclusions	48	
35	Other Exclusions:		
36	Arid Club (100% Per IPUC Order 29505)	-	
37	EEI (1/3 Per IPUC Order 29505)	-	
38	Total Exclusions	$ 48	$ (48)

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)
No	Name	2010 Actuals	2010 Adjustments
39	**John Gale**		
40	Total Expenses	$ 15,453	
41	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
42	Arid Club	-	
43	EEI	(4,738)	
44	Total	10,715	
45	Payroll Percentage Allocated to IDACORP	0.00%	
46	Net IDACORP Exclusions	-	
47	Other Exclusions:		
48	Arid Club (100% Per IPUC Order 29505)	-	
49	EEI (1/3 Per IPUC Order 29505)	1,579	
50	Total Exclusions	$ 1,579	$ (1,579)
51	**Dennis Gribble**		
52	Total Expenses	$ -	
53	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
54	Arid Club	-	
55	EEI	-	
56	Total	-	
57	Payroll Percentage Allocated to IDACORP	0.00%	
58	Net IDACORP Exclusions	-	
59	Other Exclusions:		
60	Arid Club (100% Per IPUC Order 29505)	-	
61	EEI (1/3 Per IPUC Order 29505)	-	
62	Total Exclusions	$ -	$ -
63	**Lisa Grow**		
64	Total Expenses	$ 3,097	
65	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
66	Arid Club	-	
67	EEI	-	
68	Total	3,097	
69	Payroll Percentage Allocated to IDACORP	0.00%	
70	Net IDACORP Exclusions	-	
71	Other Exclusions:		
72	Arid Club (100% Per IPUC Order 29505)	-	
73	EEI (1/3 Per IPUC Order 29505)	-	
74	Total Exclusions	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)
No	Name	2010 Actuals	2010 Adjustments
75	**Patrick Harrington**		
76	Total Expenses	$ 1,403	
77	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
78	Arid Club	-	
79	EEI	-	
80	Total	1,403	
81	Payroll Percentage Allocated to IDACORP	1.40%	
82	Net IDACORP Exclusions	20	
83	Other Exclusions:		
84	Arid Club (100% Per IPUC Order 29505)	-	
85	EEI (1/3 Per IPUC Order 29505)	-	
86	Total Exclusions	$ 20	$ (20)
87	**LaMont Keen**		
88	Total Expenses	$ 11,253	
89	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
90	Arid Club	-	
91	EEI	(8,179)	
92	Total	3,074	
93	Payroll Percentage Allocated to IDACORP	1.70%	
94	Net IDACORP Exclusions	52	
95	Other Exclusions:		
96	Arid Club (100% Per IPUC Order 29505)	-	
97	EEI (1/3 Per IPUC Order 29505)	2,726	
98	Total Exclusions	$ 2,778	$ (2,778)
99	**Steve Keen**		
100	Total Expenses	$ 3,206	
101	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
102	Arid Club	-	
103	EEI	(941)	
104	Total	2,265	
105	Payroll Percentage Allocated to IDACORP	0.60%	
106	Net IDACORP Exclusions	14	
107	Other Exclusions:		
108	Arid Club (100% Per IPUC Order 29505)	-	
109	EEI (1/3 Per IPUC Order 29505)	314	
110	Total Exclusions	$ 328	$ (328)

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)
No	Name	2010 Actuals	2010 Adjustments
111	**Warren Kline**		
112	Total Expenses	$ -	
113	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
114	Arid Club	-	
115	EEI	-	
116	Total	-	
117	Payroll Percentage Allocated to IDACORP	0.00%	
118	Net IDACORP Exclusions	-	
119	Other Exclusions:		
120	Arid Club (100% Per IPUC Order 29505)	-	
121	EEI (1/3 Per IPUC Order 29505)	-	
122	Total Exclusions	$ -	$ -
123	**Luci McDonald**		
124	Total Expenses	$ 1,899	
125	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
126	Arid Club	-	
127	EEI	(779)	
128	Total	1,120	
129	Payroll Percentage Allocated to IDACORP	2.80%	
130	Net IDACORP Exclusions	31	
131	Other Exclusions:		
132	Arid Club (100% Per IPUC Order 29505)	-	
133	EEI (1/3 Per IPUC Order 29505)	260	
134	Total Exclusions	$ 291	$ (291)
135	**Jeffrey Malmen**		
136	Total Expenses	$ -	
137	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
138	Arid Club	-	
139	EEI	-	
140	Total	-	
141	Payroll Percentage Allocated to IDACORP	87.10%	
142	Net IDACORP Exclusions	-	
143	Other Exclusions:		
144	Arid Club (100% Per IPUC Order 29505)	-	
145	EEI (1/3 Per IPUC Order 29505)	-	
146	Total Exclusions	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)
No	Name	2010 Actuals	2010 Adjustments
147	**Dan Minor**		
148	Total Expenses	$ 3,678	
149	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
150	Arid Club	-	
151	EEI	-	
152	Total	3,678	
153	Payroll Percentage Allocated to IDACORP	0.00%	
154	Net IDACORP Exclusions	-	
155	Other Exclusions:		
156	Arid Club (100% Per IPUC Order 29505)	-	
157	EEI (1/3 Per IPUC Order 29505)	-	
158	Total Exclusions	$ -	$ -
159	**Ken Petersen**		
160	Total Expenses	$ 1,946	
161	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
162	Arid Club	-	
163	EEI	-	
164	Total	1,946	
165	Payroll Percentage Allocated to IDACORP	0.30%	
166	Net IDACORP Exclusions	6	
167	Other Exclusions:		
168	Arid Club (100% Per IPUC Order 29505)	-	
169	EEI (1/3 Per IPUC Order 29505)	-	
170	Total Exclusions	$ 6	$ (6)
171	**Newell V Porter**		
172	Total Expenses	$ 3,822	
173	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
174	Arid Club	-	
175	EEI	(1,140)	
176	Total	2,682	
177	Payroll Percentage Allocated to IDACORP	0.00%	
178	Net IDACORP Exclusions	-	
179	Other Exclusions:		
180	Arid Club (100% Per IPUC Order 29505)	-	
181	EEI (1/3 Per IPUC Order 29505)	380	
182	Total Exclusions	$ 380	$ (380)

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)
No	Name	2010 Actuals	2010 Adjustments
183	**Gregory Said**		
184	Total Expenses	$ 5,739	
185	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
186	Arid Club	-	
187	EEI	(3,690)	
188	Total	2,049	
189	Payroll Percentage Allocated to IDACORP	0.00%	
190	Net IDACORP Exclusions	-	
191	Other Exclusions:		
192	Arid Club (100% Per IPUC Order 29505)	-	
193	EEI (1/3 Per IPUC Order 29505)	1,230	
194	Total Exclusions	$ 1,230	$ (1,230)
195	**Lori Smith**		
196	Total Expenses	$ 2,213	
197	IDACORP Exclusions Requiring Special Treatment (Listed Below):		
198	Arid Club	-	
199	EEI	-	
200	Total	2,213	
201	Payroll Percentage Allocated to IDACORP	4.30%	
202	Net IDACORP Exclusions	95	
203	Other Exclusions:		
204	Arid Club (100% Per IPUC Order 29505)	-	
205	EEI (1/3 Per IPUC Order 29505)	-	
206	Total Exclusions	$ 95	$ (95)
207	Total Reduction to Officer's Expenses	$ 9,158	$ (9,158)

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
OTHER EXCLUSIONS
For Twelve Months Ended December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2011		
	Account	2010 Actuals	2010 Adjustments	2010 Base	2010 Base	Other	Forecast Adjustmen	Ref No	Unadjusted Test Year	Annualizing	2011 Test Year
1	535	$ 66	$ (66)	$ -	YES	$ -	$ -		$ -	$ -	$ -
2	536	22	(22)	-	YES	-	-		-	-	-
3	537	367	(367)	-	YES	-	-		-	-	-
4	539	39	(39)	-	YES	-	-		-	-	-
5	560	119	(119)	-	YES	-	-		-	-	-
6	561	76	(76)	-	YES	-	-		-	-	-
7	570	9	(9)	-	YES	-	-		-	-	-
8	571	11	(11)	-	YES	-	-		-	-	-
9	580	525	(525)	-	YES	-	-		-	-	-
10	583	74	(74)	-	YES	-	-		-	-	-
11	584	71	(71)	-	YES	-	-		-	-	-
12	586	15	(15)	-	YES	-	-		-	-	-
13	587	55	(55)	-	YES	-	-		-	-	-
14	588	245	(245)	-	YES	-	-		-	-	-
15	592	113	(113)	-	YES	-	-		-	-	-
16	593	124	(124)	-	YES	-	-		-	-	-
17	901	103	(103)	-	YES	-	-		-	-	-
18	903	69	(69)	-	YES	-	-		-	-	-
19	908	281	(281)	-	YES	-	-		-	-	-
20	910	47	(47)	-	YES	-	-		-	-	-
21	920	89	(89)	-	YES	-	-		-	-	-
22	921	1,467	(1,467)	-	YES	-	-		-	-	-
23	926	1,027	(1,027)	-	YES	-	-		-	-	-
24	928	17	(17)	-	YES	-	-		-	-	-
25	935	16	(16)		YES	-	-		-	-	-
26	Total	$ 5,047	$ (5,047)	$ -		$ -	$ -		$ -	$ -	$ -

Idaho Power/603
Witness: Douglas N. Jones

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Douglas N. Jones
Specific Rate Base, Revenue, and Expense Adjustments Not Provided Elsewhere

July 29, 2011

Idaho Power Company
DETAIL OF ADDITIONAL RATE BASE, REVENUE AND EXPENSE ADJUSTMENTS
FOR THE YEARS 2010 AND 2011

(1) Line No.	(2) Description	(3) Account No.	(4) 2010 Ratebase	(5) 2010 Revenue	(6) 2010 Expense	(7) 2011 Ratebase	(8) 2011 Revenue	(9) 2011 Expense
1	Prairie Power Acquisition Adjustment (IPUC Order No. 29505)	114	$ (454,449)			$ -		
2	Prairie Power Acquisition Adjustment Accumulated Amortization(IPUC Order No. 29505)	115	418,472			22,723		
3	Net Prairie Power Acquisition Adjustment		$ (35,977)			$ 22,723		
4	IERCO Rate Base Adjustment (Bridger Used and Useful Adjustment - IPUC Order No. 29505)	123	$ (85,531)					
5	FSAS 87 Pension Expense (OPUC Order No. 10-064)	926						$ 8,788
6	Pension Expense Amortization (IPUC Order No. 31091)	926						$ 13,993,913
7	Pension Expense Amortization (FERC)	926						$ 129,964
8	Energy Efficiency Rider (IPUC Order No. 30189)	456		$ (42,479,689)				
9	Energy Efficiency Rider (IPUC Order No. 30189)	908			$ (42,479,689)			
10	Energy Efficiency Rider (Oregon)	456		$ (1,704,367)				
11	Energy Efficiency Rider (Oregon)	908			$ (1,704,367)			
12	Preliminary Survey and Investigation Charge - Coal Plant (IPUC Order No. 29904)	506			$ (64,325)			
13	2010 Incentive	920			$ (16,398,839)			
14	Architectural Fees Deferral (IPUC Order No. 30722)	923			$ (7,395)			
15	Intervenor Funding Amortization - CAPAI (IPUC Order No. 30978)	928						$ 4,379
16	Citizens Utility Board 2011 Funding Grant Amortization (OPUC Order No. 11-011)	928						$ 32,350
17	Citizens Utility Board 2010 Funding Grant (OPUC Order No. 10-406)	928						$ 32,772
18	Intervenor Funding - CAPAI (IPUC Order No. 30722)	928						$ 11,464
19	Intervenor Funding - Irrigators (IPUC Order No. 30722)	928						$ 38,472
20	Intervenor Funding - CAPAI (IPUC Order No. 30892)	928						$ 10,510
21	Intervenor Funding - ICL (IPUC Order No. 30892)	928						$ 9,854
22	Intervenor Funding - IIPA (IPUC Order No. 30892)	928						$ 20,677
23	Intervenor Funding - Renewable Northwest Project and NW Energy Coalition (IPUC Order No. 30488)	928			$ (2,180)			
24	Intervenor Funding - Irrigators (IPUC Order No. 30508)	928			$ (3,551)			

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT WRIGHT

July 29, 2011

Q. Please state your name and business address.

A. My name is Scott Wright. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Regulatory Analyst II in the Regulatory Affairs Department. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Business Economics from Eastern Oregon University. I have also attended the Center for Public Utilities "Practical Skills for a Changing Electric Industry" course at New Mexico State University in Albuquerque, New Mexico, as well as the Edison Electric Institute's "Electric Rate Advanced Course" in Madison, Wisconsin.

Q. Please describe your work experience.

A. In May 1998, I accepted a position as Research Assistant with Idaho Power in the Regulatory Affairs Department. In March 2007, I was promoted to a Regulatory Analyst I. In March 2010, I was promoted to a Regulatory Analyst II. As a Regulatory Analyst II, I am responsible for running the AURORA model to calculate net power supply expenses ("NPSE") for ratemaking purposes, as well as the marginal cost of energy used in the Company's marginal cost analysis. My duties also include providing analytical support for other regulatory activities within the Regulatory Affairs Department. In my current role, I served as the Company's power supply expense witness in the last three Annual Power Cost Update ("APCU") filings before the Oregon Public Utilities Commission ("Commission"), UE-203, UE-214, and UE-222.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's variable power supply expenses under the 2011 Test Year and to compare those results to variable power supply expenses currently reflected in rates as a result of the Company's 2011

October Update, the first portion of the APCU. As described in Company witness Mr. Timothy E. Tatum's testimony, the Company is not proposing to update the variable power supply expenses that have been modeled for the 2011 Test Year; instead, the Company is proposing to continue using the variable power supply expenses that were approved in Order No. 11-178 from the Company's 2011 October Update. As a result, the purpose of my testimony is to provide updated power supply expenses for informational purposes only.

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

A. Variable power supply expenses are determined for each water condition starting with 1928. In this case, 83 water conditions have been evaluated. The average of the 83 water conditions is considered a reasonable representation of power supply expenses the Company might encounter during the test year.

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

A. The Company and the Commission have used the term "power supply expense" to refer to the sum of the following Federal Energy Regulatory Commission ("FERC") accounts: (FERC Accounts 501 and 547) and purchased power expenses (FERC Account 555), excluding Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses minus surplus sales revenues (FERC Account 447). For ratemaking purposes, PURPA expenses have been quantified separately from other power supply expenses and are treated as fixed inputs to power supply modeling rather than variable inputs.

Q. How does the Company determine its normalized variable power supply expenses for ratemaking purposes?

A. The Company uses the AURORA model, which is a comprehensive electric market resource dispatch model. As with the October Update, the Company updated streamflows, loads, fuel prices, transportation costs, plant capacities, maintenance rates, heat rates, and forced outage rates for thermal plants.

Q. Please describe the changes in the Company's system loads since the 2011 October Update.

A. The Company's 2011 October Update annual normalized system load was 1,826 average megawatts ("aMW"). The Company's 2011 annual normalized system load used in the 2011 Test Year is 1,819 aMW, a decrease of 7 aMW.

Q. Why have loads decreased by 7 aMW from what was previously filed in the 2011 October Update?

A. The decrease in loads from the 2011 October Update to the 2011 Test Year can be attributed to two primary factors. First, a term sales contract with Raft River Rural Electric Cooperative ("Raft River") is scheduled to expire on September 30, 2011. The Raft River load was included in the 2011 October Update, but it was removed from the 2011 Test Year as an annualizing adjustment. Also, the 2011 October Update uses a test period of April 2011 through March 2012, whereas the 2011 Test Year is a 2011 calendar year.

Q. Is the Hoku Materials, Inc. ("Hoku") special contract load reflected in this annual normalized system load?

A. Yes. As per Mr. Tatum's instruction, the Hoku special contract load was included in the 2011 Test Year at annualized 2012 levels to reflect Hoku's anticipated loads during the time that new rates will be effective.

Q. Please explain the Hoku contract.

A. The Electric Service Agreement ("ESA") between the Company and Hoku is separated into two revenue blocks. The first block revenues of the contract are primarily the result of market based rates, while the second block revenues result from embedded cost-based rates. The energy component of the first block revenues is treated in a manner similar to surplus sales revenue, which reduces the NPSE. The first block revenue reduction of NPSE, equates to a $23.9 million benefit to customers.

Q. Was Hoku included in the 2011 October Update?

A. Yes. The Hoku load was included in the 2011 October Update for the April 2011 through March 2012 time period.

Q. How have the fuel costs of the Company's coal-fired resources changed since the 2011 October Update?

A. The fuel cost for the Bridger plant has not materially changed (from $22.33 per megawatt-hours ("MWh") to $22.21 per MWh), coal costs for Boardman have also remained relatively stable (from $18.25 per MWh to $18.07 per MWh), while coal costs for Valmy have increased (from $30.94 per MWh to $33.89 per MWh).

Q. Please explain why coal costs have increased since the 2011 October Update for the Valmy plant.

A. Coal price increases are the result of a number of factors, principally changes in mining and transportation costs. These price changes are passed to the plant via contract clauses which are tied to price indexes.

It is also worth mentioning that the unit cost at the Valmy plant has increased due to the same fixed costs being spread over smaller units of production. In other words, the amount of coal delivered to the plant has remained relatively constant, while the amount of energy production has declined from previous years, due to the economic dispatch of the plant. As mentioned earlier, this has led to a higher unit cost in terms of $/MWh than in previous years.

Q. Have natural gas prices changed since the 2011 October Update?

A. Yes. Natural gas prices have declined since the 2011 October Update. The average Henry Hub gas price for the 2011 October Update was $4.98 per MMBtu, while the average Henry Hub gas price used for the 2011 Test Year is $4.25 per MMBtu.

Q. Please explain how an increase or decrease in natural gas prices affects NPSE.

A. Natural gas prices influence electricity prices within the AURORA model. When natural gas prices are high, surplus sales revenues are greater due to higher market prices, whereas when natural gas prices are low, the inverse occurs. Because Idaho Power is a net seller of electricity under "normal" conditions, a decrease in electricity prices caused by lower gas prices results in an increase in NPSE.

Q. Have you prepared an exhibit to demonstrate the normalization of variable power supply expenses describing the changes you have described in your testimony?

A. Yes. Exhibit 701 shows the results of the variable power supply expense normalization modeling for the 2011 Test Year. Exhibit 701 also shows the summary results containing the 83-year average variable power supply generation sources and expenses.

Q. Please summarize the sources and disposition of energy shown on Exhibit 701.

A. Hydro generation supplies 8.7 million MWh, approximately 51 percent (8.7 million MWh / 17.2 million MWh = 51 percent) of the generation mix. Thermal generation supplies 5.0 million MWh (Bridger 4.0, Boardman 0.3, Valmy 0.7), approximately 29 percent (5.0 million MWh / 17.2 million MWh = 29 percent) of the generation mix. Danskin and Bennett Mountain are peaking units so they supply energy at times when resources and/or transmission lines are constrained. Purchases of power are made up of short-term and longer-term market purchases and PURPA. PURPA purchases are normalized and account for nearly 1.8 million MWh. PURPA purchases are not included on Exhibit 701; however, when combined with market purchases of 1.7 million MWh, total purchases amount to 3.5 million MWh (1.8 million MWh + 1.7 million MWh = 3.5 million MWh) approximately 20 percent (3.5 million MWh / 17.2 million MWh = 20 percent) of the generation mix. Of the 17.2 million MWh consumed, 15.9 million MWh are utilized for system loads while nearly 1.3 million MWh are sold as surplus.

Q. Please describe the expense and revenue information associated with the normalized operation you described in Exhibit 701.

A. Exhibit 701 contains variable power supply expense and revenue information limited to FERC Accounts 501, Fuel (coal); 547, Fuel (gas); 555, Purchased Power; and 447, Sales for Resale. Hydro generation has no assumed fuel expense. Coal expenses of $119.2 million are comprised of Bridger at $88.5 million, Valmy at $24.6 million, and Boardman at $6.1 million. Gas expenses of $5.3 million are comprised of Danskin and Bennett Mountain. Purchased power expenses, not including PURPA, amount to $70.8 million, surplus sales expenses amount to $36.8 million, and the Hoku first block surplus sales amount to $23.9 million. The NPSE amount to $134.6 million (119.2 + 5.3 + 70.8 – 36.8 – 23.9).

Q. How do these NPSE compare to the 2011 October Update?

A. The NPSE approved in the 2011 October Update was $118.4 million shown on Exhibit 702. The NPSE presented for the 2011 Test Year of $134.6 million represents a $16.2 million increase before PURPA repricing.

Q. Please explain why the NPSE in the 2011 Test Year is higher than the NPSE for the 2011 October Update.

A. The methodology used in the 2011 October Update used an average of forward market prices to reprice purchased power and surplus sales, while the Test Year scenario relies on AURORA to price purchased power and surplus sales.

Q. Please describe the change in PURPA generation and expenses since the 2011 October Update.

A. PURPA generation increased from 195 aMW to 207 aMW, an increase of 12 aMW. PURPA expenses also increased from $129.1 million to $132.9 million, an increase of $3.8 million. This increase was caused by additional PURPA coming on-line.

Q. Have PURPA contracts been repriced to reflect the unlevelized avoided costs?

A. Yes. PURPA contracts were repriced in both the 2011 October Update, and in the 2011 Test Year.

Q. How does the 2011 October Update NPSE including PURPA compare to the 2011 Test Year?

A. The 2011 October Update NPSE including PURPA was $247.5 million, while the 2011 NPSE including PURPA for the 2011 Test Year is $267.5 million, an increase of $20.0 million.

Q. Did you provide the results of your analysis to Mr. Tatum?

A. Yes.

Q. Is any portion of the Company's request for rate relief associated with your power supply expense analysis for the 2011 Test Year?

A. No. As mentioned earlier in my testimony, Mr. Tatum instructed me to quantify the Company's variable power supply expenses for a 2011 Test Year for information purposes only. Although my power supply expense analysis would suggest the need to increase rates, the Company is not requesting an upward adjustment to rates for power supply expenses changes. As described in Mr. Tatum's testimony, the Company believes that this matter is appropriately addressed in the context of the annual October Update component of the APCU.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright
Power Supply Expense for 2011 Normalized Loads Over
83 Water Year Conditions

July 29, 2011

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

AVERAGE

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	781,641.4	834,551.9	865,477.9	865,560.6	931,957.3	928,812.8	676,249.1	550,556.2	552,398.5	526,166.2	456,577.2	677,070.2	8,647,019.4
Bridger													
Energy (MWh)	375,072.7	324,257.9	284,091.1	196,192.6	159,202.9	135,471.9	380,850.4	420,232.3	368,078.1	427,788.0	437,123.1	475,437.9	3,983,798.9
Cost ($ x 1000)	$ 8,335.2	$ 7,200.3	$ 6,338.1	$ 4,394.6	$ 3,574.4	$ 3,054.5	$ 8,485.5	$ 9,323.0	$ 8,187.9	$ 9,482.3	$ 9,651.2	$ 10,457.0	$ 88,484.1
Boardman													
Energy (MWh)	30,164.5	28,089.6	30,690.8	13,314.7	-	17,002.0	37,787.0	37,855.7	36,025.3	35,492.0	34,519.7	37,487.3	338,428.6
Cost ($ x 1000)	$ 555.1	$ 514.4	$ 561.7	$ 247.9	$ -	$ 318.6	$ 672.8	$ 674.6	$ 643.5	$ 638.4	$ 620.4	$ 668.9	$ 6,116.3
Valmy													
Energy (MWh)	55,353.6	47,705.1	11,443.6	2,538.2	1,148.0	145.2	65,809.2	95,402.8	61,135.6	117,390.0	119,757.9	146,581.4	724,410.4
Cost ($ x 1000)	$ 1,881.4	$ 1,619.6	$ 394.5	$ 87.9	$ 39.9	$ 5.1	$ 2,247.1	$ 3,236.1	$ 2,080.1	$ 3,974.4	$ 4,047.8	$ 4,939.2	$ 24,553.1
Danskin													
Energy (MWh)	-	-	-	-	-	8.9	2,109.8	3,185.4	356.5	77.6	5.4	0.3	5,743.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.4	$ 102.7	$ 157.4	$ 18.2	$ 3.5	$ 0.2	$ 0.0	$ 282.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 437.0	$ 553.4	$ 608.3	$ 455.4	$ 454.6	$ 437.7	$ 451.5	$ 5,343.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	219.9	156.8	4.9	2.3	-	-	383.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.9	$ 8.2	$ 0.3	$ 0.1	$ -	$ -	$ 19.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.9	$ 8.2	$ 0.3	$ 0.1	$ -	$ -	$ 19.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	64,812.3	9,448.3	20,608.0	17,067.2	84,608.2	154,907.4	367,840.8	280,924.8	154,202.8	10,907.2	23,764.0	29,485.4	1,218,576.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	98,554.0	39,007.5	48,982.5	47,246.7	113,900.3	217,196.7	430,273.6	343,130.7	179,536.3	41,377.4	57,709.5	68,570.8	1,685,486.1
Market Cost ($ x 1000)	$ 1,891.4	$ 275.2	$ 601.9	$ 484.3	$ 2,445.1	$ 4,120.9	$ 12,939.3	$ 10,475.5	$ 5,696.8	$ 345.8	$ 751.3	$ 1,287.1	$ 41,314.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,734.2	$ 1,891.1	$ 1,744.2	$ 1,695.5	$ 3,623.0	$ 8,776.3	$ 17,920.8	$ 15,479.3	$ 7,083.3	$ 2,011.9	$ 2,976.5	$ 3,846.6	$ 70,782.8
Surplus Sales													
Energy (MWh)	92,507.5	220,742.7	212,402.1	198,637.7	73,765.2	51,791.2	1,860.6	5,293.8	40,348.6	157,284.0	63,522.7	144,346.3	1,262,502.5
Revenue Including Transmission Costs ($ x 1000)	$ 2,897.8	$ 6,703.7	$ 5,728.6	$ 4,934.8	$ 1,648.2	$ 781.2	$ 45.0	$ 152.6	$ 1,158.5	$ 5,699.0	$ 2,448.4	$ 5,821.7	$ 38,019.5
Transmission Costs ($ x 1000)	$ 92.5	$ 220.7	$ 212.4	$ 198.6	$ 73.8	$ 51.8	$ 1.9	$ 5.3	$ 40.3	$ 157.3	$ 63.5	$ 144.3	$ 1,262.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,805.3	$ 6,482.9	$ 5,516.2	$ 4,736.2	$ 1,574.5	$ 729.4	$ 43.1	$ 147.3	$ 1,118.1	$ 5,541.7	$ 2,384.9	$ 5,677.4	$ 36,757.0
Hoku First Block Revenues ($ x 1000)	$ 2,353.4	$ 2,125.6	$ 2,350.2	$ 2,277.5	$ 2,353.4	$ 1,498.3	$ 743.2	$ 1,254.6	$ 1,977.8	$ 2,353.4	$ 2,280.6	$ 2,353.4	$ 23,921.5
Net Power Supply Expenses ($ x 1000)	$ 9,693.0	$ 2,931.4	$ 1,571.2	$ (151.6)	$ 3,759.8	$ 10,363.9	$ 29,104.1	$ 27,927.5	$ 15,354.6	$ 8,666.6	$ 13,068.1	$ 12,332.5	$ 134,621.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1928

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,077,022.8	1,054,780.6	1,051,033.4	1,003,171.0	1,043,529.1	860,125.3	638,837.9	609,994.5	546,593.9	442,876.8	488,561.1	743,321.0	9,559,847.4
Bridger													
Energy (MWh)	441,632.7	410,191.2	345,153.1	175,760.2	75,884.3	82,036.0	393,661.4	413,448.4	389,571.2	437,109.9	447,345.5	482,673.9	4,094,467.7
Cost ($ x 1000)	$ 9,754.9	$ 9,059.0	$ 7,724.1	$ 3,957.9	$ 1,708.4	$ 1,872.4	$ 8,801.0	$ 9,212.9	$ 8,674.6	$ 9,673.0	$ 9,863.7	$ 10,602.3	$ 90,904.1
Boardman													
Energy (MWh)	38,559.3	34,720.6	39,630.0	14,690.0	-	21,791.9	40,088.5	37,470.1	36,539.7	36,662.0	35,905.5	39,578.8	375,636.4
Cost ($ x 1000)	$ 685.3	$ 617.4	$ 701.7	$ 270.8	$ -	$ 403.9	$ 708.8	$ 668.7	$ 651.3	$ 656.3	$ 641.6	$ 700.9	$ 6,706.9
Valmy													
Energy (MWh)	34,324.3	11,471.1	-	-	-	-	55,425.9	104,654.3	26,270.2	137,772.7	141,253.8	158,002.4	669,174.8
Cost ($ x 1000)	$ 1,174.4	$ 396.7	$ -	$ -	$ -	$ -	$ 1,907.7	$ 3,566.3	$ 916.4	$ 4,664.4	$ 4,774.2	$ 5,315.8	$ 22,715.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,425.4	857.7	0.0	296.9	-	-	4,579.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 147.5	$ 37.8	$ 0.0	$ 13.2	$ -	$ -	$ 198.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 598.1	$ 488.6	$ 437.1	$ 464.4	$ 437.5	$ 451.5	$ 5,259.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	613.4	-	-	-	-	-	613.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 26.7	$ -	$ -	$ -	$ -	$ -	$ 26.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 26.7	$ -	$ -	$ -	$ -	$ -	$ 26.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	3,647.2	-	536.7	1,283.2	53,107.5	223,848.7	396,940.2	220,751.0	153,837.6	11,363.9	3,908.6	1,184.6	1,070,409.1
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	37,388.9	29,559.2	28,911.2	31,462.7	82,399.7	286,137.9	459,373.0	282,956.8	179,171.2	41,834.1	37,854.1	40,269.9	1,537,318.8
Market Cost ($ x 1000)	$ 116.0	$ -	$ 19.6	$ 39.1	$ 1,496.7	$ 5,840.5	$ 13,801.4	$ 7,603.4	$ 5,590.7	$ 387.2	$ 104.5	$ 37.8	$ 35,037.0
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,958.9	$ 1,615.9	$ 1,162.0	$ 1,250.2	$ 2,674.6	$ 10,496.0	$ 18,782.9	$ 12,607.1	$ 6,977.2	$ 2,053.3	$ 2,329.7	$ 2,597.3	$ 64,505.2
Surplus Sales													
Energy (MWh)	380,660.2	487,867.6	436,456.2	298,870.4	69,392.7	3,272.9	-	4,149.4	20,962.7	105,548.1	108,751.6	203,052.4	2,118,984.2
Revenue Including Transmission Costs ($ x 1000)	$ 12,520.6	$ 15,464.8	$ 12,225.1	$ 7,334.5	$ 1,768.8	$ 72.5	$ -	$ 119.5	$ 570.4	$ 3,740.9	$ 4,165.1	$ 8,854.2	$ 66,836.5
Transmission Costs ($ x 1000)	$ 380.7	$ 487.9	$ 436.5	$ 298.9	$ 69.4	$ 3.3	$ -	$ 4.1	$ 21.0	$ 105.5	$ 108.8	$ 203.1	$ 2,119.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 12,140.0	$ 14,976.9	$ 11,788.6	$ 7,035.6	$ 1,699.4	$ 69.2	$ -	$ 115.4	$ 549.5	$ 3,635.4	$ 4,056.3	$ 8,651.2	$ 64,717.5
Net Power Supply Expenses ($ x 1000)	$ 1,779.3	$ (2,973.6)	$ (1,801.7)	$ (1,120.4)	$ 3,133.9	$ 13,139.8	$ 30,825.2	$ 26,428.2	$ 17,107.2	$ 13,876.1	$ 13,990.4	$ 11,016.6	$ 125,401.0

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1929

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	688,285.1	619,592.8	718,771.4	790,782.7	754,274.3	805,427.9	580,578.6	480,491.7	441,043.6	424,869.3	408,776.3	543,541.4	7,256,435.2
Bridger													
Energy (MWh)	478,289.8	436,117.3	455,748.9	380,815.4	292,199.6	244,588.6	452,521.4	467,905.6	432,920.7	454,915.5	459,451.3	483,288.5	5,038,762.4
Cost ($ x 1000)	$ 10,506.3	$ 9,579.3	$ 10,047.1	$ 8,439.9	$ 6,539.6	$ 5,499.5	$ 9,984.8	$ 10,305.9	$ 9,574.2	$ 10,045.1	$ 10,106.7	$ 10,614.6	$ 111,242.9
Boardman													
Energy (MWh)	37,179.5	35,202.1	38,462.0	17,677.8	-	19,958.2	39,427.3	38,245.3	36,889.6	36,930.7	37,018.7	39,654.1	376,645.5
Cost ($ x 1000)	$ 664.2	$ 624.7	$ 683.8	$ 316.6	$ -	$ 372.9	$ 698.6	$ 680.5	$ 656.7	$ 660.4	$ 658.7	$ 702.1	$ 6,719.4
Valmy													
Energy (MWh)	126,906.8	132,928.6	25,514.4	-	-	-	122,723.8	143,978.9	118,441.7	147,117.6	151,985.8	167,422.5	1,137,020.2
Cost ($ x 1000)	$ 4,314.6	$ 4,490.8	$ 894.5	$ -	$ -	$ -	$ 4,167.4	$ 4,865.8	$ 4,034.0	$ 4,966.0	$ 5,115.1	$ 5,615.2	$ 38,463.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,292.2	5,101.3	714.0	73.2	-	-	9,180.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 163.3	$ 259.7	$ 36.0	$ 3.8	$ -	$ -	$ 462.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 614.0	$ 710.5	$ 473.1	$ 455.0	$ 437.5	$ 451.5	$ 5,524.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	258.1	221.7	-	-	-	-	479.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.0	$ 11.4	$ -	$ -	$ -	$ -	$ 24.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.0	$ 11.4	$ -	$ -	$ -	$ -	$ 24.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	5,743.3	-	4,074.3	-	94,594.8	129,318.0	330,388.3	254,811.6	144,775.3	5,634.2	5,869.2	28,939.9	1,004,148.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	39,485.1	29,559.2	32,448.8	30,179.5	123,886.9	191,607.2	392,821.1	317,017.4	170,108.8	36,104.4	39,814.8	68,025.3	1,471,058.5
Market Cost ($ x 1000)	$ 198.8	$ -	$ 139.0	$ -	$ 2,941.1	$ 3,650.0	$ 13,583.0	$ 11,096.3	$ 6,189.8	$ 240.7	$ 252.2	$ 1,388.8	$ 39,679.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,041.6	$ 1,615.9	$ 1,281.3	$ 1,211.1	$ 4,119.1	$ 8,305.4	$ 18,564.5	$ 16,100.0	$ 7,576.3	$ 1,906.8	$ 2,477.4	$ 3,948.3	$ 69,147.7
Surplus Sales													
Energy (MWh)	121,879.5	200,551.5	242,674.3	293,252.1	37,929.1	14,750.4	190.3	7,735.3	42,930.5	109,000.7	54,878.5	41,135.6	1,166,907.8
Revenue Including Transmission Costs ($ x 1000)	$ 4,790.9	$ 7,696.3	$ 7,859.3	$ 8,874.0	$ 982.2	$ 388.0	$ 5.1	$ 229.6	$ 1,299.6	$ 4,217.5	$ 2,320.0	$ 2,007.9	$ 40,670.6
Transmission Costs ($ x 1000)	$ 121.9	$ 200.6	$ 242.7	$ 293.3	$ 37.9	$ 14.8	$ 0.2	$ 7.7	$ 42.9	$ 109.0	$ 54.9	$ 41.1	$ 1,166.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 4,669.1	$ 7,495.8	$ 7,616.6	$ 8,580.8	$ 944.3	$ 373.3	$ 5.0	$ 221.8	$ 1,256.7	$ 4,108.5	$ 2,265.1	$ 1,966.8	$ 39,503.6
Net Power Supply Expenses ($ x 1000)	$ 13,203.4	$ 9,129.4	$ 5,689.3	$ 1,823.1	$ 10,164.7	$ 14,241.2	$ 34,037.3	$ 32,452.3	$ 21,057.6	$ 13,924.8	$ 16,530.2	$ 19,364.9	$ 191,618.2

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1930

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	563,426.1	726,948.5	664,073.1	516,206.0	700,680.1	644,111.9	557,281.7	469,240.3	437,395.3	411,832.8	404,157.4	474,856.1	6,570,209.3
Bridger													
Energy (MWh)	483,442.6	436,348.0	479,560.5	379,288.0	302,365.9	279,206.5	475,507.8	472,063.4	437,426.2	462,983.0	459,098.3	483,436.8	5,150,726.8
Cost ($ x 1000)	$ 10,617.7	$ 9,584.0	$ 10,539.8	$ 8,409.2	$ 6,754.7	$ 6,256.7	$ 10,458.4	$ 10,389.3	$ 9,664.6	$ 10,207.1	$ 10,099.6	$ 10,617.6	$ 113,598.7
Boardman													
Energy (MWh)	39,537.4	34,952.1	39,091.4	16,481.6	-	21,573.7	38,916.1	38,066.2	36,356.4	37,353.0	36,864.5	39,904.4	379,096.8
Cost ($ x 1000)	$ 700.3	$ 620.9	$ 693.5	$ 298.3	$ -	$ 400.7	$ 690.8	$ 677.8	$ 648.5	$ 666.9	$ 656.3	$ 705.9	$ 6,760.0
Valmy													
Energy (MWh)	160,061.6	135,175.7	87,311.8	23,140.2	14,300.8	970.0	135,435.5	150,686.3	141,834.8	152,869.2	152,611.1	169,245.7	1,323,642.7
Cost ($ x 1000)	$ 5,381.4	$ 4,562.1	$ 2,983.8	$ 806.2	$ 499.6	$ 35.0	$ 4,597.2	$ 5,083.4	$ 4,792.8	$ 5,152.6	$ 5,134.9	$ 5,673.2	$ 44,702.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	4,197.7	4,597.6	859.4	268.7	-	-	9,923.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 222.7	$ 250.3	$ 46.3	$ 14.8	$ -	$ -	$ 534.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 673.3	$ 701.1	$ 483.4	$ 466.0	$ 437.5	$ 451.5	$ 5,595.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	168.9	296.4	-	-	-	-	465.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.1	$ 16.4	$ -	$ -	$ -	$ -	$ 25.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.1	$ 16.4	$ -	$ -	$ -	$ -	$ 25.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	14,132.2	-	130.4	30,864.5	114,087.8	240,289.8	317,899.8	256,743.0	136,086.7	6,603.4	7,090.2	66,196.8	1,190,124.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	47,874.0	29,559.2	28,504.9	61,044.1	143,379.9	302,579.1	380,332.6	318,948.9	161,420.2	37,073.6	41,035.7	105,282.1	1,657,034.3
Market Cost ($ x 1000)	$ 584.8	$ -	$ 3.6	$ 941.6	$ 3,832.8	$ 7,296.3	$ 14,241.0	$ 11,924.9	$ 6,246.4	$ 317.1	$ 308.3	$ 3,568.9	$ 49,265.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,427.6	$ 1,615.9	$ 1,145.9	$ 2,152.7	$ 5,010.7	$ 11,951.8	$ 19,222.5	$ 16,928.6	$ 7,632.9	$ 1,983.2	$ 2,533.6	$ 6,128.4	$ 78,733.8
Surplus Sales													
Energy (MWh)	46,084.9	310,128.8	270,268.4	69,958.4	28,293.2	1,616.3	405.0	8,668.5	58,100.1	111,369.7	51,594.8	11,931.2	968,419.2
Revenue Including Transmission Costs ($ x 1000)	$ 1,904.9	$ 12,276.4	$ 9,334.0	$ 2,318.4	$ 679.9	$ 46.9	$ 11.4	$ 258.8	$ 1,863.1	$ 4,447.1	$ 2,281.5	$ 583.8	$ 36,006.0
Transmission Costs ($ x 1000)	$ 46.1	$ 310.1	$ 270.3	$ 70.0	$ 28.3	$ 1.6	$ 0.4	$ 8.7	$ 58.1	$ 111.4	$ 51.6	$ 11.9	$ 968.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,858.8	$ 11,966.3	$ 9,063.7	$ 2,248.4	$ 651.6	$ 45.2	$ 11.0	$ 250.1	$ 1,805.0	$ 4,335.7	$ 2,229.9	$ 571.9	$ 35,037.5
Net Power Supply Expenses ($ x 1000)	$ 17,614.1	$ 4,731.0	$ 6,698.3	$ 9,854.2	$ 12,063.8	$ 19,035.5	$ 35,640.4	$ 33,546.5	$ 21,417.3	$ 14,140.0	$ 16,631.9	$ 23,004.8	$ 214,377.9

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1931

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,436.7	403,279.5	592,957.3	493,047.1	567,671.0	482,498.1	531,044.0	439,720.1	402,995.7	370,766.3	400,086.8	473,080.6	5,677,583.2
Bridger													
Energy (MWh)	483,424.2	436,657.8	478,917.5	396,861.8	299,012.2	289,057.7	478,003.3	478,445.6	434,106.7	460,159.6	459,519.9	483,405.8	5,177,571.9
Cost ($ x 1000)	$ 10,617.3	$ 9,590.2	$ 10,526.9	$ 8,761.9	$ 6,676.3	$ 6,476.5	$ 10,508.5	$ 10,517.4	$ 9,598.0	$ 10,150.4	$ 10,108.1	$ 10,617.0	$ 114,148.5
Boardman													
Energy (MWh)	39,015.6	35,698.8	38,638.1	17,472.0	-	21,776.9	39,531.2	38,940.7	36,383.8	36,657.5	36,680.9	39,784.1	380,579.6
Cost ($ x 1000)	$ 692.3	$ 632.4	$ 686.5	$ 313.5	$ -	$ 403.8	$ 700.2	$ 691.2	$ 649.0	$ 656.2	$ 653.5	$ 704.1	$ 6,782.7
Valmy													
Energy (MWh)	160,327.8	142,060.1	82,521.8	29,956.2	20,438.8	4,974.6	136,255.4	154,491.3	141,167.0	151,095.1	152,498.1	168,869.7	1,344,656.0
Cost ($ x 1000)	$ 5,389.8	$ 4,780.8	$ 2,819.4	$ 1,034.0	$ 709.7	$ 175.9	$ 4,620.1	$ 5,204.3	$ 4,771.6	$ 5,096.4	$ 5,131.3	$ 5,661.3	$ 45,394.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	5,922.2	7,250.4	2,444.8	92.9	-	-	15,710.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 314.9	$ 395.4	$ 131.9	$ 5.1	$ -	$ -	$ 847.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 765.6	$ 846.2	$ 569.0	$ 456.3	$ 437.5	$ 451.5	$ 5,908.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	469.1	603.1	61.8	-	-	-	1,134.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 25.3	$ 33.4	$ 3.4	$ -	$ -	$ -	$ 62.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 25.3	$ 33.4	$ 3.4	$ -	$ -	$ -	$ 62.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	27,849.7	32,935.8	70.5	33,171.1	222,263.2	386,224.0	338,052.1	275,320.4	156,636.1	17,697.0	7,605.1	68,321.9	1,566,146.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	61,591.4	62,495.0	28,445.0	63,350.6	251,555.3	448,513.3	400,484.8	337,526.2	181,969.7	48,167.2	41,550.6	107,407.3	2,033,056.5
Market Cost ($ x 1000)	$ 1,124.9	$ 1,503.2	$ 2.0	$ 1,130.5	$ 7,571.3	$ 11,842.5	$ 15,438.2	$ 13,110.7	$ 7,239.8	$ 834.6	$ 337.4	$ 3,633.9	$ 63,768.9
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,967.8	$ 3,119.1	$ 1,144.3	$ 2,341.6	$ 8,749.3	$ 16,498.0	$ 20,419.7	$ 18,114.5	$ 8,626.3	$ 2,500.7	$ 2,562.6	$ 6,193.4	$ 93,237.1
Surplus Sales													
Energy (MWh)	16,536.0	27,347.3	193,205.5	74,490.7	6,245.5	-	281.4	11,753.7	41,938.1	75,925.5	48,163.1	11,751.3	507,638.0
Revenue Including Transmission Costs ($ x 1000)	$ 673.2	$ 1,045.6	$ 6,665.5	$ 2,496.5	$ 142.3	$ -	$ 8.3	$ 356.4	$ 1,325.2	$ 2,963.2	$ 2,114.1	$ 574.9	$ 18,365.3
Transmission Costs ($ x 1000)	$ 16.5	$ 27.3	$ 193.2	$ 74.5	$ 6.2	$ -	$ 0.3	$ 11.8	$ 41.9	$ 75.9	$ 48.2	$ 11.8	$ 507.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 656.7	$ 1,018.3	$ 6,472.3	$ 2,422.0	$ 136.1	$ -	$ 8.1	$ 344.7	$ 1,283.2	$ 2,887.2	$ 2,065.9	$ 563.2	$ 17,857.7
Net Power Supply Expenses ($ x 1000)	$ 19,356.4	$ 17,418.6	$ 9,103.9	$ 10,465.2	$ 16,449.5	$ 23,990.9	$ 37,031.3	$ 35,062.3	$ 22,934.0	$ 15,972.7	$ 16,827.0	$ 23,064.0	$ 247,675.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1932

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,206.4	503,415.7	740,345.5	742,883.2	868,651.4	933,995.4	612,577.6	470,279.6	443,959.0	458,786.7	404,166.2	486,087.8	7,185,354.4
Bridger													
Energy (MWh)	469,846.5	420,209.2	351,047.5	270,379.9	254,348.2	200,391.3	416,182.0	449,733.5	418,258.0	450,191.5	454,777.0	482,984.5	4,638,349.3
Cost ($ x 1000)	$ 10,344.8	$ 9,260.0	$ 7,871.9	$ 6,075.8	$ 5,709.2	$ 4,513.7	$ 9,257.6	$ 9,941.1	$ 9,265.1	$ 9,950.3	$ 10,012.9	$ 10,608.5	$ 102,811.1
Boardman													
Energy (MWh)	33,221.6	30,463.4	28,390.8	13,364.6	-	18,302.5	37,298.2	37,342.8	36,927.4	36,812.8	35,200.6	38,356.9	345,681.4
Cost ($ x 1000)	$ 603.6	$ 552.2	$ 529.6	$ 250.5	$ -	$ 347.3	$ 666.0	$ 666.7	$ 657.3	$ 658.6	$ 630.8	$ 682.2	$ 6,244.9
Valmy													
Energy (MWh)	105,145.6	94,058.9	901.8	-	-	-	94,053.0	125,793.3	99,983.7	145,664.6	146,321.9	164,917.4	976,840.4
Cost ($ x 1000)	$ 3,599.2	$ 3,225.4	$ 32.6	$ -	$ -	$ -	$ 3,210.9	$ 4,273.3	$ 3,407.5	$ 4,920.2	$ 4,935.2	$ 5,535.6	$ 33,139.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	848.6	5,763.5	610.2	29.9	-	-	7,252.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 40.7	$ 283.5	$ 29.7	$ 1.5	$ -	$ -	$ 355.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 491.3	$ 734.3	$ 466.8	$ 452.7	$ 437.5	$ 451.5	$ 5,416.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	248.7	-	-	-	-	248.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.4	$ -	$ -	$ -	$ -	$ 12.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.4	$ -	$ -	$ -	$ -	$ 12.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	92,645.3	19,995.8	25,299.8	20,646.5	48,824.5	90,312.2	368,054.8	298,262.0	161,034.2	2,848.5	14,716.0	62,084.1	1,204,723.9
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	126,387.1	49,555.0	53,674.3	50,826.1	78,116.7	152,601.5	430,487.6	360,467.9	186,367.8	33,318.7	48,661.6	101,169.5	1,671,633.6
Market Cost ($ x 1000)	$ 3,070.2	$ 583.4	$ 709.9	$ 589.0	$ 1,300.7	$ 2,003.6	$ 13,453.5	$ 12,014.3	$ 6,493.3	$ 105.7	$ 538.7	$ 2,897.8	$ 43,760.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,913.0	$ 2,199.3	$ 1,852.3	$ 1,800.1	$ 2,478.7	$ 6,659.1	$ 18,435.0	$ 17,018.0	$ 7,879.8	$ 1,771.8	$ 2,763.9	$ 5,457.3	$ 73,228.3
Surplus Sales													
Energy (MWh)	6,539.3	44,846.2	146,069.2	151,237.4	68,669.9	58,443.0	-	4,401.1	28,916.8	133,793.8	46,958.0	12,718.8	702,593.5
Revenue Including Transmission Costs ($ x 1000)	$ 266.6	$ 1,684.3	$ 4,333.7	$ 4,291.6	$ 1,862.3	$ 1,535.3	$ -	$ 128.9	$ 866.7	$ 5,136.1	$ 1,973.4	$ 583.5	$ 22,662.5
Transmission Costs ($ x 1000)	$ 6.5	$ 44.8	$ 146.1	$ 151.2	$ 68.7	$ 58.4	$ -	$ 4.4	$ 28.9	$ 133.8	$ 47.0	$ 12.7	$ 702.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 260.1	$ 1,639.4	$ 4,187.7	$ 4,140.3	$ 1,793.7	$ 1,476.9	$ -	$ 124.5	$ 837.8	$ 5,002.3	$ 1,926.4	$ 570.8	$ 21,959.9
Net Power Supply Expenses ($ x 1000)	$ 19,546.3	$ 13,911.9	$ 6,497.8	$ 4,422.4	$ 6,844.5	$ 10,479.9	$ 32,060.8	$ 32,521.4	$ 20,838.6	$ 12,751.3	$ 16,853.9	$ 22,164.3	$ 198,893.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1933

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,271.8	565,333.9	551,872.8	642,570.1	682,673.2	985,097.4	585,693.4	477,935.8	443,953.7	450,149.7	403,085.6	496,889.8	6,805,527.0
Bridger													
Energy (MWh)	419,463.0	384,980.8	390,433.3	293,437.6	278,178.5	151,536.4	396,177.9	437,472.3	400,944.6	422,821.3	424,148.4	458,034.8	4,457,629.0
Cost ($ x 1000)	$ 9,310.2	$ 8,553.0	$ 8,706.7	$ 6,572.7	$ 6,230.5	$ 3,456.3	$ 8,840.4	$ 9,695.0	$ 8,902.9	$ 9,386.2	$ 9,398.1	$ 10,107.7	$ 99,159.9
Boardman													
Energy (MWh)	29,510.7	27,853.7	30,724.7	14,179.6	-	5,517.3	34,941.5	35,763.5	35,499.5	33,115.2	30,523.4	31,240.6	308,869.9
Cost ($ x 1000)	$ 546.8	$ 512.2	$ 565.3	$ 263.0	$ -	$ 109.7	$ 629.9	$ 642.5	$ 635.4	$ 602.0	$ 559.2	$ 573.2	$ 5,639.3
Valmy													
Energy (MWh)	72,941.6	52,526.1	450.9	-	-	-	64,621.9	117,899.3	87,591.6	138,065.9	136,736.5	146,267.6	817,101.3
Cost ($ x 1000)	$ 2,501.5	$ 1,809.2	$ 16.3	$ -	$ -	$ -	$ 2,208.6	$ 4,007.8	$ 2,990.2	$ 4,677.7	$ 4,628.4	$ 4,943.1	$ 27,782.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	1,830.0	3,775.8	617.4	-	-	-	6,223.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 86.1	$ 182.3	$ 29.5	$ -	$ -	$ -	$ 297.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 536.8	$ 633.1	$ 466.6	$ 451.2	$ 437.5	$ 451.5	$ 5,359.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	58.4	-	-	-	-	58.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.9	$ -	$ -	$ -	$ -	$ 2.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.9	$ -	$ -	$ -	$ -	$ 2.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	174,886.2	42,593.2	63,559.0	38,207.5	162,564.6	95,851.9	445,759.8	312,225.1	180,107.3	18,409.6	50,310.1	99,606.1	1,684,080.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	208,628.0	72,152.4	91,933.5	68,387.0	191,856.8	158,141.2	508,192.6	374,430.9	205,440.8	48,879.8	84,255.7	138,691.5	2,150,990.1
Market Cost ($ x 1000)	$ 5,201.4	$ 1,135.3	$ 1,802.5	$ 1,082.0	$ 4,926.2	$ 1,975.8	$ 15,246.9	$ 11,793.7	$ 6,951.3	$ 547.0	$ 1,443.5	$ 3,361.7	$ 55,467.2
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 7,044.3	$ 2,751.1	$ 2,944.9	$ 2,293.2	$ 6,104.1	$ 6,631.3	$ 20,228.4	$ 16,797.4	$ 8,337.8	$ 2,213.1	$ 3,668.7	$ 5,921.1	$ 84,935.4
Surplus Sales													
Energy (MWh)	2,532.6	49,982.4	37,139.4	92,370.4	20,282.7	53,413.0	-	2,097.2	16,855.1	102,009.5	36,566.2	10,299.6	423,548.3
Revenue Including Transmission Costs ($ x 1000)	$ 101.0	$ 1,814.7	$ 1,135.8	$ 2,742.0	$ 478.3	$ 1,080.3	$ -	$ 57.8	$ 490.9	$ 3,819.6	$ 1,491.9	$ 458.6	$ 13,670.7
Transmission Costs ($ x 1000)	$ 2.5	$ 50.0	$ 37.1	$ 92.4	$ 20.3	$ 53.4	$ -	$ 2.1	$ 16.9	$ 102.0	$ 36.6	$ 10.3	$ 423.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 98.4	$ 1,764.8	$ 1,098.6	$ 2,649.6	$ 458.0	$ 1,026.9	$ -	$ 55.7	$ 474.0	$ 3,717.6	$ 1,455.3	$ 448.3	$ 13,247.2
Net Power Supply Expenses ($ x 1000)	$ 19,650.1	$ 12,175.2	$ 11,533.7	$ 6,915.6	$ 12,327.0	$ 9,607.1	$ 32,444.2	$ 31,723.0	$ 20,859.0	$ 13,612.5	$ 17,236.5	$ 21,548.5	$ 209,632.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1934

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	541,189.2	533,436.0	512,237.8	506,225.0	697,354.8	325,974.6	419,060.0	413,977.6	406,697.5	394,812.1	397,555.0	466,979.8	5,615,499.5
Bridger													
Energy (MWh)	392,707.5	345,250.0	347,395.1	208,075.2	245,127.2	271,048.9	445,377.1	468,380.7	424,264.1	455,789.7	454,074.1	481,972.4	4,539,462.0
Cost ($ x 1000)	$ 8,752.3	$ 7,711.3	$ 7,769.1	$ 4,695.3	$ 5,492.1	$ 6,081.9	$ 9,853.7	$ 10,315.4	$ 9,385.7	$ 10,062.7	$ 9,998.8	$ 10,588.2	$ 100,706.5
Boardman													
Energy (MWh)	22,179.1	24,755.7	28,136.6	8,280.6	-	24,735.2	38,999.0	38,334.6	36,886.4	36,689.4	34,970.4	38,336.0	332,303.0
Cost ($ x 1000)	$ 423.4	$ 464.8	$ 525.7	$ 161.6	$ -	$ 455.3	$ 692.1	$ 681.9	$ 656.7	$ 656.7	$ 627.3	$ 681.9	$ 6,027.3
Valmy													
Energy (MWh)	53,893.3	42,561.9	2,397.9	-	-	-	125,502.8	145,961.0	117,500.4	147,959.1	147,739.1	165,173.0	948,688.6
Cost ($ x 1000)	$ 1,865.3	$ 1,454.1	$ 86.2	$ -	$ -	$ -	$ 4,258.5	$ 4,928.7	$ 4,001.3	$ 4,993.1	$ 4,980.2	$ 5,543.7	$ 32,111.0
Danskin													
Energy (MWh)	-	-	-	-	-	736.8	22,080.2	7,927.8	2,252.5	103.9	-	-	33,101.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 35.1	$ 1,098.0	$ 403.5	$ 113.4	$ 5.4	$ -	$ -	$ 1,655.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 471.7	$ 1,548.7	$ 854.4	$ 550.6	$ 456.5	$ 437.5	$ 451.5	$ 6,716.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	5,749.9	744.7	80.2	-	-	-	6,574.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 289.2	$ 38.4	$ 4.1	$ -	$ -	$ -	$ 331.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 289.2	$ 38.4	$ 4.1	$ -	$ -	$ -	$ 331.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	207,606.0	101,672.6	122,670.2	187,792.0	175,186.6	562,024.8	472,222.9	313,900.8	172,034.2	10,854.0	15,160.9	78,679.7	2,419,804.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	241,347.7	131,231.9	151,044.7	217,971.6	204,478.7	624,314.0	534,655.7	376,106.6	197,367.8	41,324.2	49,106.5	117,765.1	2,886,714.4
Market Cost ($ x 1000)	$ 5,454.0	$ 2,480.7	$ 3,284.7	$ 4,989.0	$ 4,923.5	$ 16,776.3	$ 20,254.4	$ 13,621.4	$ 7,406.1	$ 461.0	$ 551.9	$ 3,789.2	$ 83,992.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 7,296.9	$ 4,096.5	$ 4,427.1	$ 6,200.1	$ 6,101.5	$ 21,431.8	$ 25,235.9	$ 18,625.1	$ 8,792.6	$ 2,127.1	$ 2,777.1	$ 6,348.7	$ 113,460.3
Surplus Sales													
Energy (MWh)	3,005.4	24,343.9	12,916.6	14,322.1	14,507.4	-	-	6,209.2	27,863.4	85,667.1	41,273.0	9,427.5	239,535.5
Revenue Including Transmission Costs ($ x 1000)	$ 111.0	$ 850.6	$ 378.2	$ 392.1	$ 277.7	$ -	$ -	$ 183.5	$ 834.0	$ 3,244.4	$ 1,751.2	$ 427.9	$ 8,450.6
Transmission Costs ($ x 1000)	$ 3.0	$ 24.3	$ 12.9	$ 14.3	$ 14.5	$ -	$ -	$ 6.2	$ 27.9	$ 85.7	$ 41.3	$ 9.4	$ 239.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 108.0	$ 826.3	$ 365.3	$ 377.8	$ 263.2	$ -	$ -	$ 177.3	$ 806.2	$ 3,158.7	$ 1,709.9	$ 418.4	$ 8,211.1
Net Power Supply Expenses ($ x 1000)	$ 18,575.6	$ 13,214.8	$ 12,841.8	$ 11,115.5	$ 11,780.8	$ 28,440.7	$ 41,878.0	$ 35,266.6	$ 22,584.7	$ 15,137.4	$ 17,110.9	$ 23,195.6	$ 251,142.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1935

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,361.8	415,705.1	487,680.7	573,096.0	622,831.1	592,650.9	548,219.0	458,304.5	429,118.2	408,485.5	404,313.2	468,317.9	5,929,083.9
Bridger													
Energy (MWh)	452,478.6	419,301.4	453,166.8	366,394.1	295,280.3	262,717.4	447,433.4	468,615.6	433,286.8	460,160.9	459,438.4	483,391.9	5,001,665.7
Cost ($ x 1000)	$ 9,996.2	$ 9,241.8	$ 10,010.0	$ 8,150.4	$ 6,601.4	$ 5,891.6	$ 9,895.0	$ 10,320.1	$ 9,581.5	$ 10,150.4	$ 10,106.4	$ 10,616.7	$ 110,561.7
Boardman													
Energy (MWh)	30,906.8	29,542.3	33,868.4	15,260.7	-	19,524.2	37,366.6	38,144.8	36,440.6	37,165.7	36,936.0	39,903.5	355,059.4
Cost ($ x 1000)	$ 568.1	$ 538.1	$ 613.5	$ 279.6	$ -	$ 369.0	$ 667.1	$ 679.0	$ 649.8	$ 664.0	$ 657.4	$ 705.9	$ 6,391.5
Valmy													
Energy (MWh)	130,046.1	129,823.2	19,007.8	-	-	-	115,807.8	145,742.7	140,645.9	151,297.0	152,974.8	168,625.1	1,153,970.2
Cost ($ x 1000)	$ 4,399.1	$ 4,392.1	$ 669.1	$ -	$ -	$ -	$ 3,930.7	$ 4,924.7	$ 4,752.7	$ 5,102.7	$ 5,146.5	$ 5,653.5	$ 38,971.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,203.2	5,198.1	1,189.0	226.7	-	-	9,817.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 164.9	$ 274.6	$ 62.1	$ 12.1	$ -	$ -	$ 513.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 615.5	$ 725.4	$ 499.3	$ 463.3	$ 437.5	$ 451.5	$ 5,575.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	48.1	276.6	-	-	-	-	324.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.5	$ 14.8	$ -	$ -	$ -	$ -	$ 17.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.5	$ 14.8	$ -	$ -	$ -	$ -	$ 17.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	90,497.9	48,105.3	34,667.5	25,718.3	193,318.3	309,655.7	376,935.6	276,390.7	140,084.8	7,435.4	7,207.2	72,622.0	1,582,638.9
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	124,239.6	77,664.6	63,042.0	55,897.9	222,610.5	371,944.9	439,368.4	338,596.6	165,418.3	37,905.6	41,152.8	111,707.4	2,049,548.6
Market Cost ($ x 1000)	$ 2,708.3	$ 1,607.2	$ 1,058.8	$ 729.9	$ 6,250.5	$ 8,457.3	$ 15,178.4	$ 12,261.2	$ 6,258.0	$ 332.4	$ 314.3	$ 3,785.3	$ 58,941.4
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,551.2	$ 3,223.0	$ 2,201.1	$ 1,941.0	$ 7,428.4	$ 13,112.7	$ 20,159.9	$ 17,264.9	$ 7,644.5	$ 1,998.4	$ 2,539.5	$ 6,344.8	$ 88,409.6
Surplus Sales													
Energy (MWh)	9,746.6	19,175.8	28,483.6	84,442.0	8,290.2	-	-	9,648.8	48,908.1	104,230.6	52,645.6	11,151.8	376,723.1
Revenue Including Transmission Costs ($ x 1000)	$ 366.4	$ 724.5	$ 895.3	$ 2,679.2	$ 184.8	$ -	$ -	$ 291.1	$ 1,542.1	$ 4,077.1	$ 2,274.1	$ 518.2	$ 13,552.9
Transmission Costs ($ x 1000)	$ 9.7	$ 19.2	$ 28.5	$ 84.4	$ 8.3	$ -	$ -	$ 9.6	$ 48.9	$ 104.2	$ 52.6	$ 11.2	$ 376.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 356.6	$ 705.4	$ 866.8	$ 2,594.8	$ 176.5	$ -	$ -	$ 281.5	$ 1,493.2	$ 3,972.9	$ 2,221.4	$ 507.1	$ 13,176.2
Net Power Supply Expenses ($ x 1000)	$ 19,503.9	$ 17,004.2	$ 13,026.0	$ 8,212.5	$ 14,303.6	$ 19,809.9	$ 35,270.6	$ 33,647.5	$ 21,634.7	$ 14,406.0	$ 16,665.8	$ 23,265.3	$ 236,749.9

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1936

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,507.2	537,660.6	615,416.6	982,264.0	997,317.6	759,635.6	581,484.5	488,518.4	444,031.9	458,936.4	407,351.7	484,606.9	7,277,731.3
Bridger													
Energy (MWh)	481,436.6	436,093.9	437,104.5	290,050.1	232,423.1	221,740.9	450,182.3	464,316.2	423,520.2	450,669.5	457,996.4	483,265.2	4,828,798.9
Cost ($ x 1000)	$ 10,577.4	$ 9,578.9	$ 9,658.2	$ 6,493.1	$ 5,218.7	$ 4,981.6	$ 9,947.4	$ 10,233.8	$ 9,370.8	$ 9,959.9	$ 10,077.5	$ 10,614.1	$ 106,711.3
Boardman													
Energy (MWh)	36,585.0	34,828.6	34,824.0	14,201.5	-	22,589.5	39,511.3	38,519.3	36,726.7	36,848.3	36,923.3	39,697.1	371,254.7
Cost ($ x 1000)	$ 655.1	$ 619.0	$ 628.1	$ 263.4	$ -	$ 422.4	$ 699.9	$ 684.7	$ 654.2	$ 659.1	$ 657.2	$ 702.8	$ 6,646.0
Valmy													
Energy (MWh)	119,625.9	119,891.6	811.7	-	-	-	114,804.1	142,620.7	115,100.1	147,213.9	151,349.5	168,662.9	1,080,080.3
Cost ($ x 1000)	$ 4,081.8	$ 4,075.5	$ 29.4	$ -	$ -	$ -	$ 3,912.8	$ 4,817.8	$ 3,918.8	$ 4,973.1	$ 5,094.9	$ 5,654.7	$ 36,558.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,420.9	5,376.8	600.5	22.1	-	-	9,420.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 167.3	$ 269.9	$ 29.8	$ 1.1	$ -	$ -	$ 468.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 618.0	$ 720.7	$ 466.9	$ 452.3	$ 437.5	$ 451.5	$ 5,529.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	474.2	332.5	-	-	-	-	806.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.5	$ 16.9	$ -	$ -	$ -	$ -	$ 40.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.5	$ 16.9	$ -	$ -	$ -	$ -	$ 40.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	68,082.7	265.1	17,693.9	197.7	15,746.7	186,393.0	339,182.9	250,105.1	149,941.6	3,472.9	8,806.0	59,329.2	1,099,216.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	101,824.4	29,824.4	46,068.4	30,377.2	45,038.9	248,682.3	401,615.6	312,310.9	175,275.1	33,943.1	42,751.5	98,414.6	1,566,126.5
Market Cost ($ x 1000)	$ 2,408.6	$ 7.5	$ 549.7	$ 7.0	$ 381.8	$ 5,075.4	$ 13,572.4	$ 10,636.5	$ 6,237.7	$ 126.7	$ 365.1	$ 2,957.1	$ 42,325.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,251.5	$ 1,623.4	$ 1,692.0	$ 1,218.1	$ 1,559.8	$ 9,730.9	$ 18,553.9	$ 15,640.2	$ 7,624.2	$ 1,792.8	$ 2,590.4	$ 5,516.6	$ 71,793.7
Surplus Sales													
Energy (MWh)	11,716.9	105,449.9	105,946.0	390,669.4	142,312.5	5,817.6	59.8	6,767.1	38,066.9	136,622.9	54,204.8	13,855.9	1,011,489.6
Revenue Including Transmission Costs ($ x 1000)	$ 475.4	$ 4,012.2	$ 3,240.4	$ 10,571.6	$ 3,572.6	$ 144.7	$ 1.8	$ 199.4	$ 1,153.7	$ 5,342.9	$ 2,287.9	$ 643.2	$ 31,645.9
Transmission Costs ($ x 1000)	$ 11.7	$ 105.4	$ 105.9	$ 390.7	$ 142.3	$ 5.8	$ 0.1	$ 6.8	$ 38.1	$ 136.6	$ 54.2	$ 13.9	$ 1,011.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 463.6	$ 3,906.8	$ 3,134.5	$ 10,181.0	$ 3,430.3	$ 138.9	$ 1.8	$ 192.7	$ 1,115.6	$ 5,206.3	$ 2,233.6	$ 629.4	$ 30,634.4
Net Power Supply Expenses ($ x 1000)	$ 19,448.0	$ 12,304.4	$ 9,272.3	$ (1,770.2)	$ 3,798.5	$ 15,432.6	$ 33,753.8	$ 31,921.6	$ 20,919.3	$ 12,630.9	$ 16,623.8	$ 22,310.3	$ 196,645.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1937

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,362.5	412,164.1	589,997.4	552,945.4	744,743.0	649,255.0	561,309.5	470,213.7	446,709.4	509,985.3	405,550.3	589,457.9	6,452,693.4
Bridger													
Energy (MWh)	483,442.6	436,569.6	481,374.4	408,201.4	300,413.8	278,930.6	477,437.8	478,092.7	432,934.3	453,274.3	455,971.6	483,359.6	5,170,002.8
Cost ($ x 1000)	$ 10,617.7	$ 9,588.4	$ 10,576.2	$ 8,989.5	$ 6,715.5	$ 6,251.1	$ 10,497.2	$ 10,510.3	$ 9,574.5	$ 10,012.2	$ 10,036.8	$ 10,616.0	$ 113,985.5
Boardman													
Energy (MWh)	40,092.8	35,756.0	39,247.5	18,303.9	-	22,287.4	39,432.6	38,708.1	36,452.8	36,298.8	35,656.2	38,641.1	380,877.4
Cost ($ x 1000)	$ 708.8	$ 633.2	$ 695.9	$ 326.2	$ -	$ 414.7	$ 698.7	$ 687.6	$ 650.0	$ 650.7	$ 637.8	$ 686.6	$ 6,790.3
Valmy													
Energy (MWh)	163,248.3	142,520.9	96,210.1	49,733.7	9,229.1	-	134,895.1	154,027.5	141,489.8	148,435.7	150,117.1	167,602.1	1,357,509.3
Cost ($ x 1000)	$ 5,482.6	$ 4,795.4	$ 3,281.1	$ 1,711.8	$ 323.2	$ -	$ 4,576.1	$ 5,189.5	$ 4,781.9	$ 5,011.9	$ 5,055.6	$ 5,620.9	$ 45,829.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	4,173.0	5,521.2	766.7	-	-	-	10,460.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 221.4	$ 300.5	$ 41.3	$ -	$ -	$ -	$ 563.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 672.0	$ 751.4	$ 478.4	$ 451.2	$ 437.5	$ 451.5	$ 5,624.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	244.4	379.5	-	-	-	-	623.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.1	$ 20.9	$ -	$ -	$ -	$ -	$ 34.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.1	$ 20.9	$ -	$ -	$ -	$ -	$ 34.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	27,505.6	27,529.3	-	5,264.2	86,283.7	236,040.7	311,958.4	248,178.0	132,637.1	1,694.7	12,963.2	15,927.7	1,105,982.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	61,247.3	57,088.5	28,374.5	35,443.7	115,575.8	298,329.9	374,391.1	310,383.8	157,970.6	32,164.9	46,908.7	55,013.0	1,572,892.1
Market Cost ($ x 1000)	$ 1,198.8	$ 1,242.3	$ -	$ 191.9	$ 2,824.8	$ 7,098.3	$ 14,182.1	$ 11,777.3	$ 6,117.6	$ 51.3	$ 528.2	$ 662.5	$ 45,875.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,041.6	$ 2,858.2	$ 1,142.4	$ 1,403.0	$ 4,002.7	$ 11,753.8	$ 19,163.6	$ 16,781.0	$ 7,504.1	$ 1,717.4	$ 2,753.4	$ 3,222.0	$ 75,343.3
Surplus Sales													
Energy (MWh)	20,142.6	31,256.1	206,932.8	138,435.7	37,525.0	1,975.9	451.9	12,101.5	59,131.4	189,141.7	52,028.8	73,273.3	822,396.7
Revenue Including Transmission Costs ($ x 1000)	$ 828.4	$ 1,223.5	$ 7,196.7	$ 4,666.3	$ 939.1	$ 58.2	$ 13.5	$ 382.2	$ 1,942.3	$ 7,977.3	$ 2,323.8	$ 3,965.3	$ 31,516.7
Transmission Costs ($ x 1000)	$ 20.1	$ 31.3	$ 206.9	$ 138.4	$ 37.5	$ 2.0	$ 0.5	$ 12.1	$ 59.1	$ 189.1	$ 52.0	$ 73.3	$ 822.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 808.3	$ 1,192.3	$ 6,989.8	$ 4,527.8	$ 901.6	$ 56.2	$ 13.1	$ 370.1	$ 1,883.2	$ 7,788.1	$ 2,271.8	$ 3,892.1	$ 30,694.3
Net Power Supply Expenses ($ x 1000)	$ 19,388.3	$ 16,997.4	$ 9,104.8	$ 8,339.0	$ 10,590.2	$ 18,800.0	$ 35,607.7	$ 33,570.7	$ 21,105.7	$ 10,055.2	$ 16,649.4	$ 16,705.0	$ 216,913.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1938

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	550,966.8	770,204.1	870,727.0	938,908.1	1,138,307.2	1,160,857.0	738,184.1	521,476.5	510,938.1	508,794.6	407,436.8	764,612.8	8,881,413.1
Bridger													
Energy (MWh)	418,142.8	382,088.1	283,850.3	121,091.7	103,035.9	117,538.8	391,650.8	443,537.0	394,427.7	440,850.5	453,854.6	482,863.3	4,032,931.6
Cost ($ x 1000)	$ 9,283.7	$ 8,494.9	$ 6,386.7	$ 2,747.0	$ 2,338.8	$ 2,684.9	$ 8,757.8	$ 9,816.8	$ 8,772.1	$ 9,762.8	$ 9,994.3	$ 10,606.1	$ 89,646.0
Boardman													
Energy (MWh)	29,397.3	28,281.0	29,444.6	13,799.2	-	21,664.5	37,869.2	38,631.3	36,345.4	35,814.8	36,116.1	39,370.5	346,733.8
Cost ($ x 1000)	$ 545.0	$ 518.7	$ 545.7	$ 257.2	$ -	$ 405.2	$ 674.8	$ 686.4	$ 648.4	$ 643.3	$ 644.9	$ 697.8	$ 6,267.4
Valmy													
Energy (MWh)	15,331.1	5,177.1	-	-	-	-	54,438.5	113,835.6	50,559.4	139,175.1	144,031.1	160,818.8	683,366.6
Cost ($ x 1000)	$ 527.7	$ 178.4	$ -	$ -	$ -	$ -	$ 1,864.4	$ 3,868.2	$ 1,735.5	$ 4,709.3	$ 4,862.4	$ 5,405.2	$ 23,151.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	127.6	4,334.7	126.3	9.9	-	-	4,598.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.7	$ 198.8	$ 5.7	$ 0.5	$ -	$ -	$ 210.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 456.4	$ 649.6	$ 442.8	$ 451.6	$ 437.5	$ 451.5	$ 5,272.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	112.5	-	-	-	-	112.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.2	$ -	$ -	$ -	$ -	$ 5.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.2	$ -	$ -	$ -	$ -	$ 5.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	206,008.4	3,913.6	23,644.9	4,837.5	16,781.1	20,293.9	307,078.5	264,792.2	159,790.3	3,656.9	16,082.1	1,145.9	1,028,025.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	239,750.1	33,472.8	52,019.4	35,017.0	46,073.3	82,583.2	369,511.3	326,998.0	185,123.8	34,127.1	50,027.7	40,231.2	1,494,935.0
Market Cost ($ x 1000)	$ 6,248.4	$ 99.2	$ 707.5	$ 146.0	$ 464.6	$ 537.4	$ 10,489.4	$ 10,111.4	$ 5,877.0	$ 100.8	$ 584.6	$ 36.5	$ 35,402.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 8,091.2	$ 1,715.0	$ 1,849.9	$ 1,357.1	$ 1,642.6	$ 5,192.8	$ 15,470.9	$ 15,115.1	$ 7,263.5	$ 1,766.9	$ 2,809.8	$ 2,595.9	$ 64,870.8
Surplus Sales													
Energy (MWh)	5,309.9	166,356.5	207,760.0	182,601.0	154,960.0	135,793.4	336.9	3,703.9	20,330.8	167,762.5	49,300.4	227,099.8	1,321,315.0
Revenue Including Transmission Costs ($ x 1000)	$ 186.6	$ 5,385.7	$ 5,754.0	$ 4,551.5	$ 3,465.5	$ 2,851.9	$ 10.5	$ 101.9	$ 572.6	$ 6,247.8	$ 1,963.2	$ 10,269.2	$ 41,360.4
Transmission Costs ($ x 1000)	$ 5.3	$ 166.4	$ 207.8	$ 182.6	$ 155.0	$ 135.8	$ 0.3	$ 3.7	$ 20.3	$ 167.8	$ 49.3	$ 227.1	$ 1,321.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 181.3	$ 5,219.4	$ 5,546.3	$ 4,368.9	$ 3,310.6	$ 2,716.1	$ 10.1	$ 98.2	$ 552.2	$ 6,080.0	$ 1,913.9	$ 10,042.1	$ 40,039.0
Net Power Supply Expenses ($ x 1000)	$ 18,612.2	$ 6,002.2	$ 3,635.2	$ 428.6	$ 1,121.1	$ 6,003.4	$ 27,214.1	$ 30,043.1	$ 18,310.1	$ 11,254.0	$ 16,835.0	$ 9,714.4	$ 149,173.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1939

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	661,997.8	755,940.7	928,490.4	954,831.4	942,172.5	703,223.6	564,207.2	477,788.7	443,994.4	480,422.8	405,247.3	494,440.0	7,812,756.7
Bridger													
Energy (MWh)	471,573.3	434,441.4	445,832.1	318,567.6	263,423.1	245,123.7	449,926.6	464,957.7	428,139.4	447,811.0	456,698.7	483,319.7	4,909,814.2
Cost ($ x 1000)	$ 10,379.5	$ 9,545.7	$ 9,848.1	$ 7,118.9	$ 5,903.9	$ 5,509.3	$ 9,941.9	$ 10,246.7	$ 9,478.2	$ 9,902.5	$ 10,051.4	$ 10,615.2	$ 108,541.4
Boardman													
Energy (MWh)	34,846.5	35,178.8	37,563.8	14,823.0	-	21,167.9	39,343.4	38,107.3	36,696.0	36,109.3	36,499.8	39,681.7	370,017.5
Cost ($ x 1000)	$ 628.5	$ 624.4	$ 670.1	$ 272.9	$ -	$ 394.5	$ 697.3	$ 678.4	$ 653.7	$ 647.8	$ 650.7	$ 702.5	$ 6,620.9
Valmy													
Energy (MWh)	116,430.1	128,226.2	5,684.3	-	-	-	113,248.7	141,039.7	114,245.8	146,260.9	150,266.7	167,133.0	1,082,535.4
Cost ($ x 1000)	$ 3,977.8	$ 4,336.7	$ 204.0	$ -	$ -	$ -	$ 3,857.8	$ 4,764.0	$ 3,891.1	$ 4,942.8	$ 5,060.5	$ 5,606.0	$ 36,640.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,780.4	5,132.2	756.6	0.0	-	-	9,669.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 185.7	$ 258.6	$ 37.7	$ 0.0	$ -	$ -	$ 482.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 636.3	$ 709.5	$ 474.8	$ 451.2	$ 437.5	$ 451.5	$ 5,543.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	535.8	303.6	-	-	-	-	839.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 26.7	$ 15.5	$ -	$ -	$ -	$ -	$ 42.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 26.7	$ 15.5	$ -	$ -	$ -	$ -	$ 42.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	15,378.2	-	963.7	-	20,206.8	221,600.3	358,009.2	263,662.8	147,069.8	2,798.5	9,966.4	55,384.5	1,095,040.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	49,120.0	29,559.2	29,338.2	30,179.5	49,499.0	283,889.6	420,441.9	325,868.7	172,403.3	33,268.7	43,911.9	94,469.9	1,561,950.0
Market Cost ($ x 1000)	$ 431.0	$ -	$ 35.0	$ -	$ 527.2	$ 6,341.4	$ 14,388.6	$ 11,233.8	$ 6,244.4	$ 91.2	$ 399.8	$ 2,674.6	$ 42,367.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,273.8	$ 1,615.9	$ 1,177.4	$ 1,211.1	$ 1,705.1	$ 10,996.9	$ 19,370.1	$ 16,237.5	$ 7,630.9	$ 1,757.3	$ 2,625.0	$ 5,234.1	$ 71,835.3
Surplus Sales													
Energy (MWh)	85,697.5	330,491.9	418,627.3	392,183.1	122,646.8	6,582.2	51.1	7,970.3	39,047.7	152,859.7	50,455.7	18,248.8	1,624,862.1
Revenue Including Transmission Costs ($ x 1000)	$ 3,320.5	$ 12,207.3	$ 12,753.3	$ 11,009.9	$ 3,418.1	$ 169.5	$ 1.4	$ 234.0	$ 1,194.8	$ 6,028.0	$ 2,124.5	$ 872.8	$ 53,334.0
Transmission Costs ($ x 1000)	$ 85.7	$ 330.5	$ 418.6	$ 392.2	$ 122.6	$ 6.6	$ 0.1	$ 8.0	$ 39.0	$ 152.9	$ 50.5	$ 18.2	$ 1,624.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,234.8	$ 11,876.8	$ 12,334.7	$ 10,617.7	$ 3,295.5	$ 162.9	$ 1.3	$ 226.0	$ 1,155.8	$ 5,875.1	$ 2,074.0	$ 854.5	$ 51,709.1
Net Power Supply Expenses ($ x 1000)	$ 14,370.7	$ 4,560.3	$ (36.0)	$ (1,578.5)	$ 4,763.9	$ 17,174.4	$ 34,528.9	$ 32,425.6	$ 20,973.1	$ 11,826.5	$ 16,751.1	$ 21,754.9	$ 177,514.9

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1940

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	523,550.7	747,383.7	945,137.2	853,061.2	994,582.5	676,610.1	565,527.9	467,175.1	480,842.8	506,612.5	404,675.2	525,584.0	7,690,742.9
Bridger													
Energy (MWh)	479,579.9	428,323.5	403,735.4	287,940.2	277,306.9	253,126.0	454,162.4	470,055.1	422,515.6	443,367.8	457,045.3	483,259.8	4,860,417.9
Cost ($ x 1000)	$ 10,540.2	$ 9,422.9	$ 8,973.7	$ 6,447.9	$ 6,207.5	$ 5,687.1	$ 10,030.0	$ 10,349.0	$ 9,365.3	$ 9,813.4	$ 10,058.4	$ 10,614.0	$ 107,509.4
Boardman													
Energy (MWh)	35,305.6	33,114.4	32,929.3	12,874.9	-	20,049.4	39,494.5	38,936.2	36,198.7	35,569.7	36,592.4	39,647.0	360,712.1
Cost ($ x 1000)	$ 635.5	$ 592.8	$ 599.1	$ 243.0	$ -	$ 373.8	$ 699.7	$ 691.1	$ 646.1	$ 639.5	$ 652.2	$ 702.0	$ 6,474.8
Valmy													
Energy (MWh)	116,043.5	101,700.2	811.7	-	-	-	116,581.5	145,121.4	102,019.2	143,208.4	149,991.0	167,297.3	1,042,774.2
Cost ($ x 1000)	$ 3,960.8	$ 3,472.5	$ 29.4	$ -	$ -	$ -	$ 3,974.0	$ 4,902.0	$ 3,478.3	$ 4,841.8	$ 5,051.7	$ 5,611.2	$ 35,321.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	4,149.1	5,938.3	274.2	-	-	-	10,361.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 203.0	$ 298.1	$ 13.6	$ -	$ -	$ -	$ 514.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 653.6	$ 748.9	$ 450.7	$ 451.2	$ 437.5	$ 451.5	$ 5,576.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	303.8	541.6	-	-	-	-	845.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.1	$ 27.6	$ -	$ -	$ -	$ -	$ 42.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.1	$ 27.6	$ -	$ -	$ -	$ -	$ 42.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	70,919.0	-	518.5	2,890.6	6,471.3	242,272.6	348,827.5	263,261.7	131,816.7	3,245.4	9,770.6	35,638.4	1,115,632.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	104,660.7	29,559.2	28,893.0	33,070.1	35,763.4	304,561.9	411,260.3	325,467.5	157,150.3	33,715.6	43,716.2	74,723.8	1,582,542.0
Market Cost ($ x 1000)	$ 2,433.9	$ -	$ 16.0	$ 86.4	$ 174.3	$ 6,778.1	$ 14,103.4	$ 11,386.1	$ 5,346.1	$ 90.2	$ 391.6	$ 1,595.3	$ 42,401.4
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,276.7	$ 1,615.9	$ 1,158.4	$ 1,297.5	$ 1,352.2	$ 11,433.5	$ 19,084.9	$ 16,389.8	$ 6,732.6	$ 1,756.3	$ 2,616.9	$ 4,154.8	$ 71,869.6
Surplus Sales													
Energy (MWh)	10,873.7	287,221.3	383,215.0	260,727.9	175,214.9	7,523.4	48.4	8,011.9	41,805.7	171,458.4	49,852.4	29,716.8	1,425,669.7
Revenue Including Transmission Costs ($ x 1000)	$ 427.0	$ 10,306.1	$ 11,065.3	$ 7,312.4	$ 5,013.0	$ 211.2	$ 1.3	$ 232.8	$ 1,297.6	$ 6,807.9	$ 2,106.3	$ 1,447.9	$ 46,228.9
Transmission Costs ($ x 1000)	$ 10.9	$ 287.2	$ 383.2	$ 260.7	$ 175.2	$ 7.5	$ 0.0	$ 8.0	$ 41.8	$ 171.5	$ 49.9	$ 29.7	$ 1,425.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 416.1	$ 10,018.8	$ 10,682.1	$ 7,051.7	$ 4,837.7	$ 203.7	$ 1.3	$ 224.8	$ 1,255.8	$ 6,636.4	$ 2,056.5	$ 1,418.2	$ 44,803.2
Net Power Supply Expenses ($ x 1000)	$ 19,342.9	$ 5,399.6	$ 477.5	$ 1,373.1	$ 3,172.3	$ 17,727.4	$ 34,456.0	$ 32,883.7	$ 19,417.3	$ 10,865.9	$ 16,760.1	$ 20,115.4	$ 181,991.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1941

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	545,622.8	654,167.1	680,863.9	613,038.0	877,461.5	838,420.6	591,782.0	516,770.6	500,677.4	502,375.7	402,997.6	583,328.9	7,307,506.1
Bridger													
Energy (MWh)	477,678.8	434,762.1	453,609.8	335,092.4	283,072.7	236,721.7	450,096.8	466,081.4	399,904.6	432,785.6	448,713.8	478,966.3	4,897,486.1
Cost ($ x 1000)	$ 10,502.0	$ 9,552.1	$ 10,004.2	$ 7,473.6	$ 6,334.3	$ 5,322.8	$ 9,948.4	$ 10,269.3	$ 8,867.3	$ 9,601.0	$ 9,891.2	$ 10,527.9	$ 108,294.0
Boardman													
Energy (MWh)	34,308.2	34,581.1	38,714.5	14,625.6	-	21,001.0	39,542.2	38,709.7	35,418.9	34,427.7	33,202.9	33,470.9	358,002.7
Cost ($ x 1000)	$ 620.2	$ 615.2	$ 687.7	$ 269.9	$ -	$ 391.2	$ 700.4	$ 687.6	$ 634.2	$ 622.1	$ 600.2	$ 607.4	$ 6,436.2
Valmy													
Energy (MWh)	116,059.4	112,755.8	19,660.3	-	-	-	113,985.8	134,165.6	100,822.9	140,318.1	143,647.0	152,837.0	1,034,252.0
Cost ($ x 1000)	$ 3,965.3	$ 3,844.5	$ 698.3	$ -	$ -	$ -	$ 3,882.8	$ 4,548.6	$ 3,443.1	$ 4,750.9	$ 4,850.3	$ 5,151.8	$ 35,135.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,730.1	4,577.8	71.5	8.6	-	-	7,388.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 133.5	$ 228.9	$ 3.5	$ 0.4	$ -	$ -	$ 366.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 584.2	$ 679.7	$ 440.7	$ 451.6	$ 437.5	$ 451.5	$ 5,427.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	306.1	154.1	-	-	-	-	460.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.1	$ 7.8	$ -	$ -	$ -	$ -	$ 22.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.1	$ 7.8	$ -	$ -	$ -	$ -	$ 22.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	57,593.0	-	5,439.2	28,808.7	24,711.9	118,584.4	330,649.0	230,327.9	135,396.6	8,007.2	23,385.2	36,037.4	998,940.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	91,334.8	29,559.2	33,813.7	58,988.2	54,004.0	180,873.6	393,081.8	292,533.8	160,730.2	38,477.4	57,330.8	75,122.8	1,465,850.3
Market Cost ($ x 1000)	$ 1,924.2	$ -	$ 189.1	$ 795.1	$ 656.8	$ 2,991.4	$ 13,245.7	$ 9,856.0	$ 5,333.5	$ 222.4	$ 801.7	$ 1,129.0	$ 37,144.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,767.0	$ 1,615.9	$ 1,331.4	$ 2,006.2	$ 1,834.8	$ 7,646.9	$ 18,227.2	$ 14,859.8	$ 6,720.0	$ 1,888.5	$ 3,026.9	$ 3,688.5	$ 66,613.0
Surplus Sales													
Energy (MWh)	16,736.4	212,971.4	198,394.1	95,537.4	82,102.4	30,186.6	93.0	7,768.4	40,428.0	157,372.0	43,716.5	62,909.0	948,215.1
Revenue Including Transmission Costs ($ x 1000)	$ 661.7	$ 7,880.9	$ 6,419.2	$ 2,841.4	$ 2,394.7	$ 840.2	$ 2.6	$ 226.3	$ 1,254.5	$ 6,173.4	$ 1,830.0	$ 3,008.2	$ 33,533.1
Transmission Costs ($ x 1000)	$ 16.7	$ 213.0	$ 198.4	$ 95.5	$ 82.1	$ 30.2	$ 0.1	$ 7.8	$ 40.4	$ 157.4	$ 43.7	$ 62.9	$ 948.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 644.9	$ 7,667.9	$ 6,220.8	$ 2,745.9	$ 2,312.6	$ 810.0	$ 2.5	$ 218.6	$ 1,214.0	$ 6,016.0	$ 1,786.3	$ 2,945.3	$ 32,584.9
Net Power Supply Expenses ($ x 1000)	$ 18,555.5	$ 8,274.2	$ 6,899.9	$ 7,440.1	$ 6,306.7	$ 12,987.5	$ 33,355.6	$ 30,834.2	$ 18,891.1	$ 11,298.0	$ 17,019.7	$ 17,481.8	$ 189,344.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1942

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	559,499.1	723,417.0	634,919.5	871,909.2	927,209.8	887,241.2	621,880.3	480,400.7	550,460.0	506,718.2	407,916.6	588,336.4	7,759,908.2
Bridger													
Energy (MWh)	443,280.6	389,346.3	445,257.3	306,004.8	289,351.2	240,962.7	432,331.3	454,871.4	429,329.6	451,753.9	457,228.5	483,102.3	4,822,819.8
Cost ($ x 1000)	$ 9,811.6	$ 8,640.6	$ 9,836.5	$ 6,845.2	$ 6,482.4	$ 5,422.7	$ 9,591.9	$ 10,044.3	$ 9,502.1	$ 9,981.7	$ 10,062.1	$ 10,610.9	$ 106,832.0
Boardman													
Energy (MWh)	30,233.0	28,322.1	36,990.9	14,102.6	-	21,265.5	38,156.3	37,510.2	36,697.9	36,798.7	36,118.6	38,450.1	354,646.0
Cost ($ x 1000)	$ 557.8	$ 519.4	$ 661.3	$ 261.9	$ -	$ 396.0	$ 679.2	$ 669.3	$ 653.8	$ 658.4	$ 644.9	$ 683.7	$ 6,385.5
Valmy													
Energy (MWh)	92,771.4	81,414.5	17,002.3	-	-	-	110,324.6	126,731.9	106,041.6	146,278.1	148,014.4	164,320.7	992,899.5
Cost ($ x 1000)	$ 3,183.5	$ 2,801.2	$ 603.7	$ -	$ -	$ -	$ 3,764.5	$ 4,302.0	$ 3,616.1	$ 4,940.8	$ 4,989.0	$ 5,516.6	$ 33,717.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	697.9	4,085.2	2.7	52.3	-	-	4,838.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 33.9	$ 203.8	$ 0.1	$ 2.6	$ -	$ -	$ 240.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 484.6	$ 654.7	$ 437.3	$ 453.8	$ 437.5	$ 451.5	$ 5,301.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	50.5	-	-	-	-	50.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.6	$ -	$ -	$ -	$ -	$ 2.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.6	$ -	$ -	$ -	$ -	$ 2.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	103,089.4	3,630.6	6,509.9	1,244.7	10,002.8	88,260.3	325,766.1	285,949.2	87,703.7	1,219.3	11,971.4	19,189.2	944,536.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	136,831.1	33,189.9	34,884.4	31,424.2	39,294.9	150,549.6	388,198.9	348,155.0	113,037.2	31,689.5	45,917.0	58,274.6	1,411,446.4
Market Cost ($ x 1000)	$ 3,006.3	$ 89.5	$ 197.8	$ 35.6	$ 285.3	$ 2,246.5	$ 12,447.0	$ 11,716.4	$ 3,597.4	$ 39.4	$ 476.7	$ 710.7	$ 34,848.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,849.2	$ 1,705.4	$ 1,340.1	$ 1,246.7	$ 1,463.3	$ 6,902.0	$ 17,428.5	$ 16,720.2	$ 4,983.9	$ 1,705.4	$ 2,701.9	$ 3,270.2	$ 64,316.7
Surplus Sales													
Energy (MWh)	14,333.9	202,823.8	140,780.5	297,222.8	123,418.4	53,193.6	148.0	6,576.0	78,376.1	182,279.3	53,027.3	71,682.9	1,223,862.5
Revenue Including Transmission Costs ($ x 1000)	$ 561.4	$ 7,331.0	$ 4,422.3	$ 8,275.0	$ 3,533.3	$ 1,557.2	$ 4.2	$ 186.3	$ 2,467.9	$ 7,178.3	$ 2,229.8	$ 3,561.6	$ 41,308.3
Transmission Costs ($ x 1000)	$ 14.3	$ 202.8	$ 140.8	$ 297.2	$ 123.4	$ 53.2	$ 0.1	$ 6.6	$ 78.4	$ 182.3	$ 53.0	$ 71.7	$ 1,223.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 547.0	$ 7,128.1	$ 4,281.6	$ 7,977.8	$ 3,409.9	$ 1,504.0	$ 4.0	$ 179.7	$ 2,389.5	$ 6,996.0	$ 2,176.8	$ 3,489.9	$ 40,084.4
Net Power Supply Expenses ($ x 1000)	$ 18,200.9	$ 6,852.9	$ 8,559.2	$ 812.3	$ 4,986.1	$ 11,653.3	$ 31,944.5	$ 32,213.2	$ 16,803.6	$ 10,744.2	$ 16,658.6	$ 17,042.8	$ 176,471.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1943

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	817,332.2	1,017,364.4	1,093,483.4	979,066.1	1,045,801.5	1,267,887.0	914,455.1	710,864.9	607,500.6	598,261.0	532,101.6	805,259.4	10,389,377.1
Bridger													
Energy (MWh)	346,565.3	298,244.8	127,935.6	16,932.1	14,475.8	-	328,079.0	391,163.9	356,432.1	413,929.7	443,330.6	481,308.4	3,218,397.4
Cost ($ x 1000)	$ 7,762.3	$ 6,679.3	$ 2,934.1	$ 398.8	$ 336.6	$ -	$ 7,377.7	$ 8,750.8	$ 7,943.1	$ 9,183.2	$ 9,783.1	$ 10,574.9	$ 71,724.1
Boardman													
Energy (MWh)	28,101.3	26,375.6	27,713.7	7,116.4	-	17,590.8	36,799.5	37,354.6	36,819.7	36,397.0	36,005.6	39,128.4	329,402.6
Cost ($ x 1000)	$ 525.2	$ 489.6	$ 519.2	$ 142.8	$ -	$ 333.9	$ 655.6	$ 666.9	$ 655.6	$ 652.2	$ 643.2	$ 694.1	$ 5,978.1
Valmy													
Energy (MWh)	-	-	-	-	-	-	10,529.9	44,076.3	631.3	121,939.9	134,248.1	149,712.5	461,137.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 376.5	$ 1,514.8	$ 22.8	$ 4,139.9	$ 4,542.1	$ 5,052.6	$ 15,648.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	59.6	28.8	31.6	46.0	-	-	166.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.4	$ 1.2	$ 1.3	$ 1.9	$ -	$ -	$ 6.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 453.1	$ 452.0	$ 438.4	$ 453.1	$ 437.5	$ 451.5	$ 5,068.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	95,936.6	2,038.4	781.3	4,395.3	68,872.1	31,320.9	244,823.0	203,241.1	150,747.8	8,218.4	2,911.7	1,175.1	814,461.9
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	129,678.3	31,597.7	29,155.8	34,574.9	98,164.2	93,610.2	307,255.7	265,447.0	176,081.3	38,688.6	36,857.3	40,260.5	1,281,371.6
Market Cost ($ x 1000)	$ 2,561.8	$ 65.8	$ 23.7	$ 106.6	$ 1,794.0	$ 767.5	$ 7,442.2	$ 6,535.6	$ 5,224.3	$ 254.2	$ 78.6	$ 33.3	$ 24,887.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,404.7	$ 1,681.7	$ 1,166.1	$ 1,317.7	$ 2,971.9	$ 5,423.0	$ 12,423.7	$ 11,539.4	$ 6,610.8	$ 1,920.3	$ 2,303.8	$ 2,592.8	$ 54,355.8
Surplus Sales													
Energy (MWh)	73,399.9	320,710.1	249,999.9	111,436.8	26,004.0	132,221.3	5,733.1	3,703.3	20,317.5	218,260.7	140,378.6	254,873.3	1,557,038.4
Revenue Including Transmission Costs ($ x 1000)	$ 2,282.9	$ 8,858.1	$ 6,002.9	$ 1,989.2	$ 512.4	$ 1,501.9	$ 178.2	$ 102.6	$ 553.4	$ 7,632.0	$ 5,164.7	$ 10,569.3	$ 45,347.5
Transmission Costs ($ x 1000)	$ 73.4	$ 320.7	$ 250.0	$ 111.4	$ 26.0	$ 132.2	$ 5.7	$ 3.7	$ 20.3	$ 218.3	$ 140.4	$ 254.9	$ 1,557.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,209.5	$ 8,537.4	$ 5,752.9	$ 1,877.8	$ 486.3	$ 1,369.6	$ 172.5	$ 98.9	$ 533.1	$ 7,413.7	$ 5,024.3	$ 10,314.4	$ 43,790.5
Net Power Supply Expenses ($ x 1000)	$ 10,828.5	$ 627.7	$ (734.4)	$ 417.8	$ 3,272.5	$ 4,823.8	$ 21,114.1	$ 22,825.0	$ 15,137.7	$ 8,935.0	$ 12,685.4	$ 9,051.5	$ 108,984.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1944

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	729,114.3	729,058.1	771,967.4	704,943.2	762,752.5	752,938.1	600,748.0	501,248.9	489,574.8	515,398.8	410,375.7	508,416.0	7,476,535.8
Bridger													
Energy (MWh)	483,148.5	434,721.4	461,353.7	363,450.3	288,113.2	256,141.7	456,360.6	472,965.2	426,944.9	448,737.7	456,729.8	483,348.0	5,032,014.9
Cost ($ x 1000)	$ 10,611.8	$ 9,551.3	$ 10,174.4	$ 8,067.1	$ 6,446.5	$ 5,755.9	$ 10,074.1	$ 10,407.4	$ 9,454.2	$ 9,921.1	$ 10,052.1	$ 10,615.8	$ 111,131.8
Boardman													
Energy (MWh)	38,996.8	35,153.4	38,745.3	17,164.6	-	20,066.2	39,448.9	38,851.5	36,561.0	36,120.4	36,396.3	39,646.8	377,151.1
Cost ($ x 1000)	$ 692.0	$ 624.0	$ 688.2	$ 308.7	$ -	$ 374.2	$ 699.0	$ 689.8	$ 651.7	$ 648.0	$ 649.2	$ 702.0	$ 6,726.7
Valmy													
Energy (MWh)	136,133.3	129,006.7	27,207.6	-	-	-	123,075.2	146,021.4	110,790.7	145,226.7	150,117.7	168,263.4	1,135,842.7
Cost ($ x 1000)	$ 4,620.2	$ 4,361.5	$ 970.1	$ -	$ -	$ -	$ 4,180.9	$ 4,935.4	$ 3,777.5	$ 4,906.4	$ 5,055.8	$ 5,641.9	$ 38,449.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,161.7	4,791.9	151.8	-	-	-	7,105.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 107.0	$ 243.4	$ 7.6	$ -	$ -	$ -	$ 358.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 557.7	$ 694.3	$ 444.7	$ 451.2	$ 437.5	$ 451.5	$ 5,419.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	365.1	349.6	-	-	-	-	714.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 18.3	$ 18.0	$ -	$ -	$ -	$ -	$ 36.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 18.3	$ 18.0	$ -	$ -	$ -	$ -	$ 36.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	52.5	-	-	3,731.5	89,947.5	163,454.3	307,057.8	230,224.4	121,247.8	1,840.6	7,660.3	47,391.5	972,608.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	33,794.2	29,559.2	28,374.5	33,911.0	119,239.6	225,743.6	369,490.6	292,430.3	146,581.3	32,310.8	41,605.9	86,476.9	1,439,518.0
Market Cost ($ x 1000)	$ 1.5	$ -	$ -	$ 109.9	$ 2,812.8	$ 4,506.6	$ 12,601.7	$ 10,085.3	$ 5,048.0	$ 51.1	$ 305.7	$ 2,329.3	$ 37,851.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,844.3	$ 1,615.9	$ 1,142.4	$ 1,321.0	$ 3,990.7	$ 9,162.1	$ 17,583.2	$ 15,089.1	$ 6,434.4	$ 1,717.2	$ 2,530.9	$ 4,888.7	$ 67,320.0
Surplus Sales													
Energy (MWh)	172,922.2	304,645.9	299,374.0	193,266.0	37,677.2	8,059.0	217.1	11,432.6	53,410.5	186,780.6	53,056.0	25,356.7	1,346,197.8
Revenue Including Transmission Costs ($ x 1000)	$ 6,723.5	$ 11,458.7	$ 9,553.5	$ 5,847.2	$ 973.1	$ 217.4	$ 6.2	$ 333.0	$ 1,661.2	$ 7,513.7	$ 2,266.2	$ 1,231.5	$ 47,785.1
Transmission Costs ($ x 1000)	$ 172.9	$ 304.6	$ 299.4	$ 193.3	$ 37.7	$ 8.1	$ 0.2	$ 11.4	$ 53.4	$ 186.8	$ 53.1	$ 25.4	$ 1,346.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 6,550.5	$ 11,154.1	$ 9,254.1	$ 5,654.0	$ 935.4	$ 209.4	$ 5.9	$ 321.5	$ 1,607.8	$ 7,326.9	$ 2,213.1	$ 1,206.1	$ 46,438.9
Net Power Supply Expenses ($ x 1000)	$ 11,563.6	$ 5,313.1	$ 4,119.9	$ 4,479.1	$ 9,952.1	$ 15,519.5	$ 33,107.3	$ 31,512.4	$ 19,154.8	$ 10,316.9	$ 16,512.2	$ 21,093.9	$ 182,645.0

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1945

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	543,439.1	931,897.8	609,492.4	653,829.0	1,052,955.4	1,123,321.6	646,442.1	527,661.1	622,961.3	498,681.4	522,187.0	838,776.0	8,571,644.2
Bridger													
Energy (MWh)	482,397.7	420,303.3	410,397.6	319,175.8	244,743.1	170,066.1	417,567.5	458,698.4	404,697.4	444,339.1	452,841.1	482,754.2	4,707,981.2
Cost ($ x 1000)	$ 10,596.7	$ 9,261.9	$ 9,092.6	$ 7,102.2	$ 5,495.8	$ 3,853.8	$ 9,295.5	$ 10,121.1	$ 8,978.2	$ 9,832.9	$ 9,974.0	$ 10,603.9	$ 104,208.7
Boardman													
Energy (MWh)	38,013.2	33,608.1	38,201.1	17,004.4	-	20,717.4	38,154.9	38,544.9	36,667.9	36,391.5	35,841.1	38,255.4	371,400.0
Cost ($ x 1000)	$ 677.0	$ 600.3	$ 679.9	$ 306.3	$ -	$ 387.6	$ 679.1	$ 685.1	$ 653.3	$ 652.1	$ 640.6	$ 680.7	$ 6,642.1
Valmy													
Energy (MWh)	110,519.6	50,558.1	6,486.9	-	-	-	84,648.0	122,172.7	85,695.5	141,759.8	144,252.8	159,529.9	905,623.2
Cost ($ x 1000)	$ 3,775.8	$ 1,737.0	$ 231.1	$ -	$ -	$ -	$ 2,889.1	$ 4,151.2	$ 2,927.7	$ 4,792.2	$ 4,869.5	$ 5,364.3	$ 30,737.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	259.3	3,655.3	-	-	-	-	3,914.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.1	$ 174.6	$ -	$ -	$ -	$ -	$ 186.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 462.7	$ 625.5	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,248.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	73.7	-	-	-	-	73.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.6	$ -	$ -	$ -	$ -	$ 3.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.6	$ -	$ -	$ -	$ -	$ 3.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	77,447.7	-	31,857.3	30,264.3	8,394.9	17,699.6	342,005.8	240,075.6	72,257.7	2,233.7	639.9	340.2	823,216.9
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	111,189.5	29,559.2	60,231.8	60,443.8	37,687.0	79,988.9	404,438.6	302,281.4	97,591.2	32,703.9	34,585.5	39,425.6	1,290,126.6
Market Cost ($ x 1000)	$ 2,796.6	$ -	$ 1,010.9	$ 929.9	$ 253.4	$ 432.8	$ 12,465.3	$ 9,652.6	$ 2,812.9	$ 73.4	$ 17.6	$ 10.8	$ 30,456.2
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,639.5	$ 1,615.9	$ 2,153.3	$ 2,141.0	$ 1,431.3	$ 5,088.3	$ 17,446.9	$ 14,656.3	$ 4,199.4	$ 1,739.5	$ 2,242.8	$ 2,570.2	$ 59,924.4
Surplus Sales													
Energy (MWh)	37,299.1	413,065.3	96,547.4	124,259.0	202,939.1	147,251.5	71.8	7,863.5	90,421.1	162,865.7	147,536.5	297,936.6	1,728,056.5
Revenue Including Transmission Costs ($ x 1000)	$ 1,364.8	$ 13,821.1	$ 3,073.1	$ 3,640.2	$ 5,234.2	$ 3,482.0	$ 2.3	$ 224.6	$ 2,822.9	$ 6,230.4	$ 5,971.1	$ 13,550.0	$ 59,416.9
Transmission Costs ($ x 1000)	$ 37.3	$ 413.1	$ 96.5	$ 124.3	$ 202.9	$ 147.3	$ 0.1	$ 7.9	$ 90.4	$ 162.9	$ 147.5	$ 297.9	$ 1,728.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,327.5	$ 13,408.0	$ 2,976.6	$ 3,515.9	$ 5,031.3	$ 3,334.8	$ 2.2	$ 216.8	$ 2,732.5	$ 6,067.6	$ 5,823.6	$ 13,252.1	$ 57,688.8
Net Power Supply Expenses ($ x 1000)	$ 18,707.3	$ 121.6	$ 9,579.4	$ 6,469.9	$ 2,346.2	$ 6,431.5	$ 30,771.2	$ 30,026.0	$ 14,463.2	$ 11,400.3	$ 12,340.8	$ 6,418.5	$ 149,075.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1946

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,013,541.4	971,356.7	1,169,438.0	1,099,457.7	1,141,851.6	979,546.0	643,724.5	526,384.1	624,589.7	503,696.9	415,969.4	862,623.8	9,952,179.8
Bridger													
Energy (MWh)	325,428.5	302,377.2	117,578.9	43,164.3	14,281.5	28,929.2	327,114.9	391,866.9	350,128.9	413,490.0	415,160.9	449,965.6	3,179,486.7
Cost ($ x 1000)	$ 7,295.9	$ 6,752.5	$ 2,700.4	$ 1,016.9	$ 330.9	$ 670.1	$ 7,354.7	$ 8,750.2	$ 7,809.2	$ 9,169.4	$ 9,188.2	$ 9,945.8	$ 70,984.3
Boardman													
Energy (MWh)	27,929.3	27,058.8	28,058.4	12,582.1	-	20,320.9	37,233.4	38,204.1	36,307.0	36,197.9	33,593.8	33,094.3	330,580.2
Cost ($ x 1000)	$ 522.5	$ 500.0	$ 524.5	$ 238.6	$ -	$ 381.5	$ 665.0	$ 679.9	$ 647.8	$ 649.2	$ 606.2	$ 601.6	$ 6,016.9
Valmy													
Energy (MWh)	-	-	-	-	-	-	11,088.6	70,005.6	5,172.9	122,107.1	133,812.6	142,598.8	484,785.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 395.0	$ 2,402.0	$ 181.0	$ 4,143.0	$ 4,528.4	$ 4,826.6	$ 16,476.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	771.0	2,423.0	14.9	42.3	-	-	3,251.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 31.2	$ 100.6	$ 0.6	$ 1.8	$ -	$ -	$ 134.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 481.9	$ 551.4	$ 437.7	$ 453.0	$ 437.5	$ 451.5	$ 5,195.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	1.5	-	-	-	-	1.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ 0.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ 0.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	30,774.3	4,947.7	-	-	15,948.3	166,775.5	509,077.9	354,829.0	141,041.9	19,156.1	53,388.1	15,511.9	1,311,450.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	64,516.0	34,507.0	28,374.5	30,179.5	45,240.4	229,064.7	571,510.7	417,034.8	166,375.4	49,626.3	87,333.7	54,597.3	1,778,360.4
Market Cost ($ x 1000)	$ 843.8	$ 159.7	$ -	$ -	$ 403.0	$ 3,603.7	$ 15,551.2	$ 11,829.8	$ 4,761.7	$ 614.0	$ 1,673.1	$ 408.5	$ 39,848.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,686.7	$ 1,775.6	$ 1,142.4	$ 1,211.1	$ 1,581.0	$ 8,259.2	$ 20,532.7	$ 16,833.6	$ 6,148.2	$ 2,280.0	$ 3,898.3	$ 2,967.9	$ 69,316.6
Surplus Sales													
Energy (MWh)	183,130.7	282,432.1	315,155.3	259,173.7	68,919.4	11,024.9	-	697.9	25,406.4	134,159.5	43,706.6	282,065.8	1,605,872.3
Revenue Including Transmission Costs ($ x 1000)	$ 5,405.3	$ 7,981.9	$ 7,382.8	$ 6,015.9	$ 1,289.4	$ 235.3	$ -	$ 18.5	$ 682.9	$ 4,668.7	$ 1,643.2	$ 10,963.7	$ 46,287.7
Transmission Costs ($ x 1000)	$ 183.1	$ 282.4	$ 315.2	$ 259.2	$ 68.9	$ 11.0	$ -	$ 0.7	$ 25.4	$ 134.2	$ 43.7	$ 282.1	$ 1,605.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,222.2	$ 7,699.5	$ 7,067.7	$ 5,756.7	$ 1,220.5	$ 224.3	$ -	$ 17.8	$ 657.5	$ 4,534.5	$ 1,599.5	$ 10,681.6	$ 44,681.8
Net Power Supply Expenses ($ x 1000)	$ 5,628.8	$ 1,643.1	$ (2,301.3)	$ (2,853.8)	$ 1,141.7	$ 9,523.1	$ 29,429.3	$ 29,199.4	$ 14,566.4	$ 12,160.1	$ 17,059.1	$ 8,111.9	$ 123,307.7

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1947

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	867,198.2	1,038,827.2	904,525.0	1,183,144.8	983,921.1	964,671.0	631,247.9	510,244.4	532,704.1	511,378.5	405,883.3	778,190.1	9,311,935.6
Bridger													
Energy (MWh)	325,508.4	237,020.6	145,198.5	34,460.8	43,430.8	15,075.1	329,828.5	399,142.7	345,686.6	395,176.3	400,733.9	475,875.4	3,147,137.7
Cost ($ x 1000)	$ 7,306.1	$ 5,325.1	$ 3,355.6	$ 798.3	$ 1,011.8	$ 346.8	$ 7,421.4	$ 8,911.0	$ 7,702.8	$ 8,816.6	$ 8,898.7	$ 10,465.8	$ 70,360.2
Boardman													
Energy (MWh)	27,470.3	23,913.8	27,534.3	13,231.0	-	20,820.2	38,515.2	38,543.0	36,253.5	30,961.6	30,605.5	36,928.0	324,776.2
Cost ($ x 1000)	$ 515.5	$ 451.9	$ 516.5	$ 248.5	$ -	$ 389.2	$ 684.7	$ 685.1	$ 647.0	$ 569.0	$ 560.5	$ 660.4	$ 5,928.0
Valmy													
Energy (MWh)	-	-	-	-	-	-	18,408.6	77,755.5	2,577.9	95,431.1	121,520.8	147,228.4	462,922.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 648.1	$ 2,666.3	$ 89.1	$ 3,248.8	$ 4,116.8	$ 4,973.7	$ 15,742.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	1,760.3	3,873.9	317.0	-	-	-	5,951.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 71.1	$ 160.4	$ 13.0	$ -	$ -	$ -	$ 244.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 521.7	$ 611.2	$ 450.1	$ 451.2	$ 437.5	$ 451.5	$ 5,305.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	11.6	67.3	-	-	-	-	78.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ 2.8	$ -	$ -	$ -	$ -	$ 3.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ 2.8	$ -	$ -	$ -	$ -	$ 3.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	84,253.3	3,719.2	41,265.4	-	102,909.6	185,150.1	509,227.5	353,844.5	222,069.1	34,122.0	77,578.9	6,326.6	1,620,466.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	117,995.1	33,278.5	69,639.9	30,179.5	132,201.7	247,439.3	571,660.3	416,050.4	247,402.7	64,592.2	111,524.5	45,412.0	2,087,376.1
Market Cost ($ x 1000)	$ 2,223.9	$ 107.6	$ 1,119.0	$ -	$ 2,628.4	$ 4,096.8	$ 16,084.6	$ 11,907.1	$ 7,468.9	$ 936.1	$ 2,293.4	$ 173.4	$ 49,039.3
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,066.7	$ 1,723.5	$ 2,261.4	$ 1,211.1	$ 3,806.3	$ 8,752.3	$ 21,066.1	$ 16,910.9	$ 8,855.4	$ 2,602.2	$ 4,518.6	$ 2,732.9	$ 78,507.5
Surplus Sales													
Energy (MWh)	89,891.4	280,161.9	118,624.3	334,787.6	27,123.3	1,178.4	-	457.9	7,763.4	106,522.8	28,094.5	222,830.9	1,217,436.3
Revenue Including Transmission Costs ($ x 1000)	$ 2,769.4	$ 7,451.9	$ 3,025.2	$ 7,146.2	$ 631.0	$ 21.3	$ -	$ 11.7	$ 196.3	$ 3,627.0	$ 1,019.0	$ 9,037.1	$ 34,936.1
Transmission Costs ($ x 1000)	$ 89.9	$ 280.2	$ 118.6	$ 334.8	$ 27.1	$ 1.2	$ -	$ 0.5	$ 7.8	$ 106.5	$ 28.1	$ 222.8	$ 1,217.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,679.5	$ 7,171.7	$ 2,906.6	$ 6,811.4	$ 603.8	$ 20.1	$ -	$ 11.3	$ 188.5	$ 3,520.5	$ 991.0	$ 8,814.3	$ 33,718.7
Net Power Supply Expenses ($ x 1000)	$ 9,554.7	$ 643.2	$ 3,625.9	$ (4,117.2)	$ 4,664.7	$ 9,904.8	$ 30,342.5	$ 29,776.1	$ 17,555.9	$ 12,167.3	$ 17,541.1	$ 10,470.0	$ 142,128.9

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1948

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	888,664.3	940,615.6	747,225.4	948,817.6	898,697.8	1,239,790.9	656,199.1	528,135.7	530,053.6	516,132.6	411,569.3	683,898.8	8,989,800.6
Bridger													
Energy (MWh)	364,278.9	307,943.0	280,603.3	120,187.9	99,528.4	21,225.0	356,043.9	409,964.9	380,416.1	430,130.4	449,146.7	482,617.6	3,702,086.2
Cost ($ x 1000)	$ 8,155.0	$ 6,901.0	$ 6,352.3	$ 2,725.1	$ 2,269.6	$ 487.5	$ 7,977.1	$ 9,142.9	$ 8,476.1	$ 9,532.9	$ 9,899.9	$ 10,601.1	$ 82,520.6
Boardman													
Energy (MWh)	26,286.0	24,690.4	29,493.7	13,830.5	-	-	36,783.1	36,383.6	35,826.3	35,370.2	35,604.8	39,594.5	313,863.1
Cost ($ x 1000)	$ 494.3	$ 463.8	$ 546.5	$ 257.7	$ -	$ -	$ 656.3	$ 652.0	$ 640.4	$ 636.5	$ 637.0	$ 701.2	$ 5,685.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	22,180.0	100,130.5	18,383.6	132,854.6	141,973.6	159,759.8	575,282.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 765.9	$ 3,408.5	$ 638.9	$ 4,498.9	$ 4,797.1	$ 5,371.6	$ 19,480.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	612.3	2,258.9	10.9	-	0.0	-	2,882.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 26.4	$ 99.9	$ 0.5	$ -	$ 0.0	$ -	$ 126.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 477.1	$ 550.8	$ 437.6	$ 451.2	$ 437.5	$ 451.5	$ 5,188.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	54,882.9	4,472.4	52,235.3	6,345.9	139,333.1	40,629.9	457,196.3	307,173.1	180,097.0	9,407.7	18,150.8	3,837.8	1,273,762.0
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	88,624.6	34,031.6	80,609.8	36,525.4	168,625.2	102,919.2	519,629.0	369,378.9	205,430.5	39,877.9	52,096.4	42,923.2	1,740,671.7
Market Cost ($ x 1000)	$ 1,390.6	$ 122.7	$ 1,525.7	$ 184.9	$ 3,474.9	$ 719.6	$ 14,794.2	$ 10,554.2	$ 6,399.4	$ 281.1	$ 589.7	$ 130.3	$ 40,167.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,233.5	$ 1,738.6	$ 2,668.0	$ 1,396.0	$ 4,652.9	$ 5,375.1	$ 19,775.7	$ 15,557.9	$ 7,785.9	$ 1,947.2	$ 2,814.9	$ 2,689.8	$ 69,635.6
Surplus Sales													
Energy (MWh)	119,561.0	254,400.5	109,661.5	193,145.9	34,382.0	117,021.7	-	1,019.0	12,933.5	163,356.9	48,223.6	148,001.3	1,201,707.1
Revenue Including Transmission Costs ($ x 1000)	$ 3,690.5	$ 7,306.6	$ 3,155.4	$ 4,683.3	$ 547.5	$ 1,259.8	$ -	$ 25.5	$ 343.8	$ 5,939.2	$ 1,861.2	$ 6,550.2	$ 35,363.1
Transmission Costs ($ x 1000)	$ 119.6	$ 254.4	$ 109.7	$ 193.1	$ 34.4	$ 117.0	$ -	$ 1.0	$ 12.9	$ 163.4	$ 48.2	$ 148.0	$ 1,201.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,570.9	$ 7,052.2	$ 3,045.8	$ 4,490.1	$ 513.1	$ 1,142.8	$ -	$ 24.5	$ 330.9	$ 5,775.9	$ 1,813.0	$ 6,402.2	$ 34,161.4
Net Power Supply Expenses ($ x 1000)	$ 8,657.7	$ 2,365.6	$ 6,920.2	$ 324.9	$ 6,859.7	$ 5,156.4	$ 29,652.1	$ 29,287.6	$ 17,648.0	$ 11,290.9	$ 16,773.3	$ 13,413.1	$ 148,349.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1949

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	688,242.9	915,876.0	1,203,716.7	1,170,485.9	1,169,611.6	827,278.5	591,655.0	490,359.8	471,225.9	513,603.4	408,961.7	632,484.0	9,083,501.4
Bridger													
Energy (MWh)	439,465.1	375,969.3	285,075.7	106,182.3	83,152.6	148,529.3	415,326.4	444,716.9	397,935.0	449,051.1	450,347.8	482,832.9	4,078,584.5
Cost ($ x 1000)	$ 9,711.1	$ 8,372.1	$ 6,429.8	$ 2,409.0	$ 1,892.1	$ 3,379.1	$ 9,234.9	$ 9,840.4	$ 8,842.5	$ 9,927.4	$ 9,924.0	$ 10,605.5	$ 90,567.8
Boardman													
Energy (MWh)	33,507.4	28,587.9	28,632.3	13,354.5	-	22,544.2	39,795.7	38,633.4	36,745.3	37,184.4	35,041.2	38,095.8	352,122.1
Cost ($ x 1000)	$ 608.0	$ 523.4	$ 533.3	$ 250.4	$ -	$ 421.7	$ 704.3	$ 686.5	$ 654.5	$ 664.3	$ 628.4	$ 678.2	$ 6,353.0
Valmy													
Energy (MWh)	48,465.6	6,156.8	-	-	-	-	78,170.6	115,370.8	61,375.6	140,717.5	139,599.7	159,841.3	749,697.7
Cost ($ x 1000)	$ 1,667.0	$ 213.5	$ -	$ -	$ -	$ -	$ 2,668.7	$ 3,925.7	$ 2,101.8	$ 4,758.7	$ 4,716.9	$ 5,374.2	$ 25,426.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,097.9	5,456.0	570.2	48.0	-	-	9,172.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 139.7	$ 250.7	$ 25.9	$ 2.2	$ -	$ -	$ 418.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 590.3	$ 701.6	$ 463.0	$ 453.4	$ 437.5	$ 451.5	$ 5,479.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	749.5	212.2	11.6	-	-	-	973.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 34.0	$ 9.9	$ 0.5	$ -	$ -	$ -	$ 44.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 34.0	$ 9.9	$ 0.5	$ -	$ -	$ -	$ 44.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	50,975.5	-	-	-	14,499.9	189,296.9	400,199.0	292,250.0	179,387.4	1,329.9	18,431.1	8,702.9	1,155,072.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	84,717.3	29,559.2	28,374.5	30,179.5	43,792.0	251,586.2	462,631.8	354,455.8	204,720.9	31,800.0	52,376.7	47,788.3	1,621,982.3
Market Cost ($ x 1000)	$ 1,532.1	$ -	$ -	$ -	$ 353.0	$ 4,825.5	$ 14,560.2	$ 11,147.0	$ 6,733.6	$ 39.1	$ 613.1	$ 289.9	$ 40,093.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,375.0	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,531.0	$ 9,481.0	$ 19,541.8	$ 16,150.7	$ 8,120.1	$ 1,705.2	$ 2,838.3	$ 2,849.3	$ 69,561.7
Surplus Sales													
Energy (MWh)	46,128.0	303,279.1	517,502.7	393,967.4	164,080.7	3,102.9	-	3,982.5	15,399.6	181,399.6	44,158.1	100,243.9	1,773,244.6
Revenue Including Transmission Costs ($ x 1000)	$ 1,664.5	$ 9,446.5	$ 13,303.4	$ 9,027.2	$ 3,221.5	$ 41.6	$ -	$ 108.1	$ 420.9	$ 6,821.7	$ 1,743.4	$ 4,586.5	$ 50,385.4
Transmission Costs ($ x 1000)	$ 46.1	$ 303.3	$ 517.5	$ 394.0	$ 164.1	$ 3.1	$ -	$ 4.0	$ 15.4	$ 181.4	$ 44.2	$ 100.2	$ 1,773.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,618.4	$ 9,143.3	$ 12,785.9	$ 8,633.3	$ 3,057.4	$ 38.5	$ -	$ 104.1	$ 405.5	$ 6,640.3	$ 1,699.2	$ 4,486.2	$ 48,612.2
Net Power Supply Expenses ($ x 1000)	$ 14,088.4	$ 1,896.1	$ (4,281.4)	$ (4,326.5)	$ 815.9	$ 13,680.0	$ 32,774.0	$ 31,210.6	$ 19,776.9	$ 10,868.7	$ 16,845.8	$ 15,472.6	$ 148,821.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1950

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	867,731.9	920,776.9	1,110,713.7	978,377.4	701,578.4	1,110,327.4	829,233.8	661,198.1	585,262.6	682,422.8	579,853.9	916,136.4	9,943,613.1
Bridger													
Energy (MWh)	311,882.8	178,936.2	20,571.2	18,696.7	79,147.1	14,144.6	291,911.4	361,247.3	327,768.8	378,539.8	392,704.9	438,480.9	2,814,031.8
Cost ($ x 1000)	$ 7,010.5	$ 4,057.3	$ 475.6	$ 434.3	$ 1,834.7	$ 331.8	$ 6,565.8	$ 8,096.3	$ 7,321.1	$ 8,443.4	$ 8,752.3	$ 9,715.3	$ 63,038.3
Boardman													
Energy (MWh)	28,411.3	23,583.4	24,584.1	12,539.8	-	5,857.0	34,759.7	37,148.5	35,736.8	33,027.5	29,683.1	31,632.2	296,963.4
Cost ($ x 1000)	$ 529.9	$ 446.8	$ 471.3	$ 237.9	$ -	$ 115.1	$ 627.1	$ 663.7	$ 639.1	$ 600.6	$ 546.3	$ 579.2	$ 5,457.1
Valmy													
Energy (MWh)	-	-	-	-	-	-	4,328.9	7,663.8	-	92,072.1	67,976.0	135,496.5	307,537.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 156.6	$ 264.2	$ -	$ 3,134.2	$ 2,346.9	$ 4,591.0	$ 10,492.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	0.4	0.4	-	6.9	-	-	7.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 0.0	$ -	$ 0.3	$ -	$ -	$ 0.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.9	$ 437.1	$ 451.5	$ 437.5	$ 451.5	$ 5,061.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	92,065.0	33,100.3	1,601.8	13,266.9	329,330.9	86,479.2	368,856.8	316,610.8	196,128.5	14,831.9	31,731.4	16,817.9	1,500,821.2
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	125,806.7	62,659.6	29,976.3	43,446.4	358,623.0	148,768.4	431,289.6	378,816.6	221,462.0	45,302.1	65,676.9	55,903.3	1,967,730.9
Market Cost ($ x 1000)	$ 2,525.1	$ 924.4	$ 42.6	$ 371.5	$ 9,056.0	$ 1,584.4	$ 10,246.7	$ 9,985.1	$ 6,415.4	$ 441.8	$ 840.5	$ 431.2	$ 42,864.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,367.9	$ 2,540.2	$ 1,184.9	$ 1,582.6	$ 10,234.0	$ 6,239.9	$ 15,228.2	$ 14,988.9	$ 7,801.9	$ 2,107.9	$ 3,065.7	$ 2,990.7	$ 72,332.8
Surplus Sales													
Energy (MWh)	85,561.9	133,085.3	157,545.2	126,851.8	6,941.2	32,219.7	63.5	843.1	13,051.8	240,357.5	93,715.8	316,828.7	1,207,065.6
Revenue Including Transmission Costs ($ x 1000)	$ 2,688.9	$ 3,665.1	$ 3,307.2	$ 2,803.1	$ 134.9	$ 396.8	$ 1.7	$ 20.8	$ 343.8	$ 7,911.7	$ 3,320.3	$ 11,661.0	$ 36,255.4
Transmission Costs ($ x 1000)	$ 85.6	$ 133.1	$ 157.5	$ 126.9	$ 6.9	$ 32.2	$ 0.1	$ 0.8	$ 13.1	$ 240.4	$ 93.7	$ 316.8	$ 1,207.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,603.3	$ 3,532.0	$ 3,149.7	$ 2,676.2	$ 128.0	$ 364.6	$ 1.7	$ 20.0	$ 330.8	$ 7,671.3	$ 3,226.6	$ 11,344.2	$ 35,048.3
Net Power Supply Expenses ($ x 1000)	$ 9,650.9	$ 3,826.8	$ (618.8)	$ 14.9	$ 12,391.0	$ 6,758.7	$ 23,026.8	$ 24,443.9	$ 15,868.4	$ 7,066.2	$ 11,922.1	$ 6,983.5	$ 121,334.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1951

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,049,169.9	1,108,463.1	1,248,482.9	1,125,488.0	972,999.7	955,426.9	733,134.4	666,521.8	587,412.7	598,533.5	540,222.5	925,552.8	10,511,408.3
Bridger													
Energy (MWh)	162,734.6	115,025.0	13,782.6	30,623.1	10,767.7	-	261,835.2	332,485.1	270,439.6	379,897.7	387,432.1	447,258.0	2,412,280.8
Cost ($ x 1000)	$ 3,804.0	$ 2,682.4	$ 335.6	$ 732.6	$ 260.4	$ -	$ 5,933.8	$ 7,478.4	$ 6,094.2	$ 8,485.4	$ 8,616.9	$ 9,891.4	$ 54,315.3
Boardman													
Energy (MWh)	23,987.9	16,981.0	21,842.8	8,764.2	-	20,200.8	36,470.2	37,822.7	36,014.9	31,749.4	31,308.2	35,938.7	301,080.8
Cost ($ x 1000)	$ 459.1	$ 328.5	$ 416.8	$ 170.4	$ -	$ 375.9	$ 653.3	$ 674.1	$ 643.3	$ 581.0	$ 571.2	$ 645.2	$ 5,518.9
Valmy													
Energy (MWh)	-	-	-	-	-	-	9,469.4	-	-	11,333.0	-	86,038.5	106,840.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 342.6	$ -	$ -	$ 398.1	$ -	$ 2,959.7	$ 3,700.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	475.5	260.5	0.3	0.7	0.0	-	737.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.2	$ 9.7	$ 0.0	$ 0.0	$ 0.0	$ -	$ 26.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 467.8	$ 460.5	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,088.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	57,688.7	664.8	-	3.8	132,954.1	209,013.8	487,619.5	346,779.9	246,966.9	30,337.8	70,972.4	11,221.1	1,594,222.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	91,430.5	30,224.1	28,374.5	30,183.3	162,246.2	271,303.0	550,052.2	408,985.7	272,300.4	60,808.0	104,917.9	50,306.5	2,061,132.4
Market Cost ($ x 1000)	$ 1,484.6	$ 17.2	$ -	$ 0.1	$ 2,967.9	$ 4,298.2	$ 13,585.4	$ 10,431.1	$ 7,520.1	$ 872.8	$ 2,075.2	$ 301.5	$ 43,553.9
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,327.5	$ 1,633.1	$ 1,142.4	$ 1,211.2	$ 4,145.8	$ 8,953.6	$ 18,566.9	$ 15,434.9	$ 8,906.5	$ 2,538.9	$ 4,300.4	$ 2,860.9	$ 73,022.1
Surplus Sales													
Energy (MWh)	79,042.6	217,795.4	284,179.8	268,827.0	13,567.2	107.1	-	858.2	9,001.2	91,319.5	21,711.4	284,291.2	1,270,700.6
Revenue Including Transmission Costs ($ x 1000)	$ 2,160.9	$ 4,480.2	$ 5,534.8	$ 5,014.5	$ 181.5	$ 0.7	$ -	$ 20.8	$ 231.2	$ 2,820.0	$ 687.3	$ 10,261.2	$ 31,393.1
Transmission Costs ($ x 1000)	$ 79.0	$ 217.8	$ 284.2	$ 268.8	$ 13.6	$ 0.1	$ -	$ 0.9	$ 9.0	$ 91.3	$ 21.7	$ 284.3	$ 1,270.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,081.8	$ 4,262.4	$ 5,250.7	$ 4,745.7	$ 168.0	$ 0.6	$ -	$ 19.9	$ 222.2	$ 2,728.7	$ 665.6	$ 9,976.9	$ 30,122.4
Net Power Supply Expenses ($ x 1000)	$ 5,854.6	$ 696.0	$ (2,956.8)	$ (2,195.1)	$ 4,688.5	$ 9,765.6	$ 25,964.5	$ 24,027.9	$ 15,859.1	$ 9,725.9	$ 13,260.4	$ 6,831.9	$ 111,522.6

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1952

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,084,600.0	1,109,413.6	1,217,182.9	1,086,982.9	1,242,188.9	1,260,456.8	748,038.9	552,733.5	575,559.7	516,302.6	411,182.4	782,232.3	10,586,874.4
Bridger													
Energy (MWh)	311,109.6	254,274.1	146,213.7	47,869.8	-	13,996.0	319,384.0	388,737.5	336,405.2	406,166.8	439,387.2	479,362.5	3,142,906.4
Cost ($ x 1000)	$ 6,975.4	$ 5,700.9	$ 3,341.5	$ 1,123.1	$ -	$ 325.2	$ 7,187.2	$ 8,702.1	$ 7,504.3	$ 9,011.4	$ 9,689.2	$ 10,535.8	$ 70,096.1
Boardman													
Energy (MWh)	28,314.8	25,983.2	31,064.0	9,069.2	-	21,261.0	39,350.0	38,156.4	36,662.9	37,128.7	36,364.2	38,778.5	342,132.9
Cost ($ x 1000)	$ 528.4	$ 483.6	$ 570.5	$ 175.5	$ -	$ 395.9	$ 697.4	$ 679.2	$ 653.2	$ 663.4	$ 648.7	$ 688.7	$ 6,184.6
Valmy													
Energy (MWh)	-	-	-	-	-	-	10,219.5	25,467.9	-	118,832.6	102,806.1	147,684.9	405,010.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 366.4	$ 874.0	$ -	$ 4,031.0	$ 3,529.7	$ 4,988.2	$ 13,789.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	422.8	1,984.6	173.5	406.7	23.2	-	3,010.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.7	$ 80.2	$ 6.9	$ 16.6	$ 1.1	$ -	$ 121.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 467.3	$ 531.0	$ 444.1	$ 467.8	$ 438.5	$ 451.5	$ 5,182.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	12.8	-	-	12.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ -	$ -	$ 0.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ -	$ -	$ 0.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	20,617.4	81.3	-	-	10,345.1	29,239.2	411,582.3	376,433.2	195,318.8	23,237.3	42,730.7	3,561.0	1,113,146.2
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	54,359.1	29,640.6	28,374.5	30,179.5	39,637.2	91,528.5	474,015.0	438,639.0	220,652.3	53,707.5	76,676.3	42,646.4	1,580,055.9
Market Cost ($ x 1000)	$ 595.5	$ 2.3	$ -	$ -	$ 245.6	$ 736.1	$ 12,793.7	$ 12,344.2	$ 6,542.0	$ 775.3	$ 1,457.1	$ 103.8	$ 35,595.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,438.3	$ 1,618.2	$ 1,142.4	$ 1,211.1	$ 1,423.6	$ 5,391.6	$ 17,775.3	$ 17,348.0	$ 7,928.5	$ 2,441.4	$ 3,682.3	$ 2,663.3	$ 65,064.0
Surplus Sales													
Energy (MWh)	230,105.8	366,435.1	394,547.8	247,862.7	149,347.7	140,386.3	-	497.3	12,278.6	141,563.0	24,284.7	229,909.2	1,937,218.1
Revenue Including Transmission Costs ($ x 1000)	$ 6,705.6	$ 9,573.1	$ 9,330.9	$ 4,826.1	$ 2,275.0	$ 2,016.9	$ -	$ 12.1	$ 317.5	$ 4,941.1	$ 913.4	$ 9,251.2	$ 50,163.0
Transmission Costs ($ x 1000)	$ 230.1	$ 366.4	$ 394.5	$ 247.9	$ 149.3	$ 140.4	$ -	$ 0.5	$ 12.3	$ 141.6	$ 24.3	$ 229.9	$ 1,937.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 6,475.5	$ 9,206.7	$ 8,936.3	$ 4,578.3	$ 2,125.6	$ 1,876.5	$ -	$ 11.6	$ 305.2	$ 4,799.6	$ 889.1	$ 9,021.3	$ 48,225.8
Net Power Supply Expenses ($ x 1000)	$ 3,812.5	$ (1,089.5)	$ (3,482.8)	$ (1,632.4)	$ (251.8)	$ 4,672.8	$ 26,493.7	$ 28,122.6	$ 16,224.9	$ 11,816.0	$ 17,099.3	$ 10,306.2	$ 112,091.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1953

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	921,662.2	1,055,971.3	1,014,350.7	1,010,740.0	888,256.2	1,181,472.7	766,563.5	548,171.8	569,603.3	515,261.9	407,698.2	650,283.6	9,530,035.7
Bridger													
Energy (MWh)	345,561.2	263,439.8	264,263.2	178,550.7	78,893.4	44,657.0	328,855.2	403,179.6	359,192.7	426,815.1	425,596.6	480,005.7	3,599,010.3
Cost ($ x 1000)	$ 7,735.4	$ 5,908.3	$ 6,002.2	$ 4,064.0	$ 1,813.9	$ 1,030.9	$ 7,384.7	$ 9,006.8	$ 8,005.9	$ 9,466.4	$ 9,397.7	$ 10,548.7	$ 80,364.8
Boardman													
Energy (MWh)	28,273.1	24,667.7	34,233.9	15,008.0	-	16,793.7	37,747.2	37,393.7	36,803.3	35,782.6	34,522.0	37,793.7	339,018.7
Cost ($ x 1000)	$ 527.8	$ 463.4	$ 619.1	$ 275.7	$ -	$ 319.5	$ 672.9	$ 667.5	$ 655.4	$ 642.8	$ 620.4	$ 673.6	$ 6,138.1
Valmy													
Energy (MWh)	-	-	-	-	-	-	17,063.2	65,743.6	3,392.7	122,269.0	133,257.1	149,557.9	491,283.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 604.5	$ 2,256.7	$ 118.1	$ 4,145.6	$ 4,510.7	$ 5,047.6	$ 16,683.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	208.0	1,933.1	128.5	141.5	-	-	2,411.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 8.5	$ 81.4	$ 5.4	$ 6.0	$ -	$ -	$ 101.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 459.2	$ 532.3	$ 442.5	$ 457.2	$ 437.5	$ 451.5	$ 5,162.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	56,602.6	471.2	702.4	1,170.3	161,402.7	58,623.8	378,661.9	327,385.2	175,956.3	11,842.5	44,478.0	15,547.1	1,232,844.0
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	90,344.4	30,030.4	29,076.9	31,349.9	190,694.8	120,913.1	441,094.7	389,591.0	201,289.8	42,312.7	78,423.6	54,632.5	1,699,753.7
Market Cost ($ x 1000)	$ 1,536.0	$ 15.3	$ 23.0	$ 34.2	$ 4,420.2	$ 1,317.8	$ 11,804.7	$ 11,043.6	$ 6,085.9	$ 365.4	$ 1,432.2	$ 497.4	$ 38,575.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,378.8	$ 1,631.1	$ 1,165.4	$ 1,245.3	$ 5,598.1	$ 5,973.3	$ 16,786.2	$ 16,047.3	$ 7,472.4	$ 2,031.5	$ 3,657.4	$ 3,056.9	$ 68,043.8
Surplus Sales													
Energy (MWh)	137,558.3	321,232.0	313,646.0	309,439.6	25,422.9	116,976.4	88.5	787.6	13,229.6	151,578.9	37,333.0	111,474.2	1,538,767.0
Revenue Including Transmission Costs ($ x 1000)	$ 4,186.0	$ 8,747.6	$ 8,089.4	$ 7,426.2	$ 573.2	$ 1,508.1	$ 2.4	$ 20.2	$ 354.0	$ 5,337.0	$ 1,401.7	$ 4,648.4	$ 42,294.2
Transmission Costs ($ x 1000)	$ 137.6	$ 321.2	$ 313.6	$ 309.4	$ 25.4	$ 117.0	$ 0.1	$ 0.8	$ 13.2	$ 151.6	$ 37.3	$ 111.5	$ 1,538.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 4,048.4	$ 8,426.4	$ 7,775.8	$ 7,116.7	$ 547.8	$ 1,391.1	$ 2.3	$ 19.4	$ 340.8	$ 5,185.4	$ 1,364.4	$ 4,536.9	$ 40,755.4
Net Power Supply Expenses ($ x 1000)	$ 7,939.4	$ (109.1)	$ 410.0	$ (1,095.4)	$ 7,314.6	$ 6,369.2	$ 25,905.3	$ 28,491.1	$ 16,353.5	$ 11,558.0	$ 17,259.3	$ 15,241.5	$ 135,637.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1954

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	788,830.6	1,048,560.3	992,005.9	1,022,987.2	746,748.9	904,390.0	654,827.7	534,401.0	506,114.9	516,433.7	408,124.9	510,272.3	8,633,697.5
Bridger													
Energy (MWh)	371,785.7	314,540.3	202,045.4	95,312.7	79,959.8	43,179.5	355,110.9	401,932.8	369,721.0	429,420.9	434,364.1	482,927.1	3,580,300.2
Cost ($ x 1000)	$ 8,309.7	$ 7,064.2	$ 4,593.7	$ 2,174.5	$ 1,812.3	$ 994.8	$ 7,958.4	$ 8,967.0	$ 8,261.5	$ 9,533.4	$ 9,603.2	$ 10,607.4	$ 79,879.9
Boardman													
Energy (MWh)	27,659.7	24,677.1	28,504.6	13,796.5	-	16,050.6	35,170.2	34,976.0	32,769.2	34,555.4	32,287.9	38,357.9	318,805.3
Cost ($ x 1000)	$ 518.4	$ 463.6	$ 531.3	$ 257.2	$ -	$ 308.8	$ 633.4	$ 630.5	$ 593.6	$ 624.0	$ 586.2	$ 682.3	$ 5,829.2
Valmy													
Energy (MWh)	-	-	-	-	-	-	14,408.9	88,096.0	-	127,637.1	135,683.3	160,219.7	526,045.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 501.9	$ 3,002.1	$ -	$ 4,326.8	$ 4,592.5	$ 5,386.3	$ 17,809.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	383.0	1,312.1	8.3	0.0	-	-	1,703.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.4	$ 57.8	$ 0.4	$ 0.0	$ -	$ -	$ 74.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 467.1	$ 508.6	$ 437.5	$ 451.2	$ 437.5	$ 451.5	$ 5,135.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	2.3	-	-	-	-	2.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ 0.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ 0.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	82,445.5	458.4	2,729.6	3,345.1	288,996.8	223,468.5	469,122.2	322,652.6	228,907.2	9,275.9	34,519.0	53,566.3	1,719,487.1
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	116,187.2	30,017.6	31,104.1	33,524.6	318,288.9	285,757.8	531,554.9	384,858.5	254,240.8	39,746.1	68,464.6	92,651.7	2,186,396.8
Market Cost ($ x 1000)	$ 2,126.7	$ 14.4	$ 81.2	$ 93.6	$ 7,715.0	$ 4,887.7	$ 14,660.1	$ 10,768.9	$ 7,655.7	$ 249.9	$ 1,014.3	$ 2,224.2	$ 51,491.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,969.6	$ 1,630.3	$ 1,223.5	$ 1,304.8	$ 8,893.0	$ 9,543.2	$ 19,641.6	$ 15,772.6	$ 9,042.2	$ 1,916.0	$ 3,239.5	$ 4,783.7	$ 80,960.0
Surplus Sales													
Energy (MWh)	56,176.2	364,913.6	225,375.9	239,398.7	12,556.9	2,527.1	-	339.0	5,656.5	156,781.1	36,751.4	23,634.5	1,124,110.8
Revenue Including Transmission Costs ($ x 1000)	$ 1,766.3	$ 10,134.4	$ 5,906.9	$ 5,602.1	$ 209.3	$ 44.1	$ -	$ 8.4	$ 142.8	$ 5,643.6	$ 1,384.1	$ 1,008.4	$ 31,850.5
Transmission Costs ($ x 1000)	$ 56.2	$ 364.9	$ 225.4	$ 239.4	$ 12.6	$ 2.5	$ -	$ 0.3	$ 5.7	$ 156.8	$ 36.8	$ 23.6	$ 1,124.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,710.1	$ 9,769.5	$ 5,681.5	$ 5,362.7	$ 196.8	$ 41.6	$ -	$ 8.1	$ 137.1	$ 5,486.8	$ 1,347.4	$ 984.8	$ 30,726.4
Net Power Supply Expenses ($ x 1000)	$ 11,433.3	$ (297.0)	$ 1,066.1	$ (1,190.0)	$ 10,958.8	$ 11,241.8	$ 29,202.4	$ 28,872.9	$ 18,197.6	$ 11,364.6	$ 17,111.4	$ 20,926.3	$ 158,888.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1955

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	601,540.0	749,639.5	635,071.2	542,422.1	800,409.0	764,675.3	612,362.5	487,849.6	528,300.5	506,622.3	406,413.8	736,700.6	7,372,006.5
Bridger													
Energy (MWh)	438,111.5	397,747.9	411,342.7	318,782.3	289,190.4	215,901.8	404,860.7	446,789.7	422,858.6	433,811.8	426,561.7	474,994.1	4,680,953.1
Cost ($ x 1000)	$ 9,684.5	$ 8,809.2	$ 9,111.6	$ 7,104.8	$ 6,468.1	$ 4,872.1	$ 9,023.3	$ 9,882.0	$ 9,372.2	$ 9,621.6	$ 9,446.6	$ 10,448.1	$ 103,844.1
Boardman													
Energy (MWh)	30,978.5	28,747.5	35,790.7	14,066.8	-	17,862.7	35,133.8	37,390.1	36,600.8	34,406.2	30,915.2	33,557.7	335,450.0
Cost ($ x 1000)	$ 569.2	$ 525.9	$ 642.9	$ 261.3	$ -	$ 339.2	$ 632.9	$ 667.4	$ 652.3	$ 621.7	$ 565.2	$ 608.7	$ 6,086.8
Valmy													
Energy (MWh)	98,061.5	58,397.2	6,569.0	-	-	-	89,078.7	125,395.5	104,035.3	138,269.0	138,586.9	151,078.8	909,471.7
Cost ($ x 1000)	$ 3,365.7	$ 2,006.9	$ 237.3	$ -	$ -	$ -	$ 3,046.1	$ 4,260.7	$ 3,546.5	$ 4,680.5	$ 4,689.5	$ 5,096.0	$ 30,929.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	586.4	4,193.5	31.7	-	-	-	4,811.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 28.1	$ 205.8	$ 1.5	$ -	$ -	$ -	$ 235.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 478.7	$ 656.7	$ 438.7	$ 451.2	$ 437.5	$ 451.5	$ 5,296.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	32.5	-	-	-	-	32.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.6	$ -	$ -	$ -	$ -	$ 1.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.6	$ -	$ -	$ -	$ -	$ 1.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	82,492.8	2,155.1	27,876.1	73,458.6	59,376.3	193,321.1	387,004.5	286,630.2	101,810.1	8,605.1	48,283.0	12,997.4	1,284,010.2
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	116,234.6	31,714.3	56,250.5	103,638.1	88,668.4	255,610.4	449,437.2	348,836.0	127,143.7	39,075.3	82,228.6	52,082.8	1,750,919.9
Market Cost ($ x 1000)	$ 2,512.3	$ 55.6	$ 897.4	$ 2,139.3	$ 1,767.1	$ 4,851.1	$ 13,376.2	$ 11,449.8	$ 4,121.1	$ 234.8	$ 1,500.5	$ 352.3	$ 43,257.4
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,355.1	$ 1,671.5	$ 2,039.8	$ 3,350.4	$ 2,945.0	$ 9,506.5	$ 18,357.7	$ 16,453.5	$ 5,507.6	$ 1,900.9	$ 3,725.7	$ 2,911.8	$ 72,725.6
Surplus Sales													
Energy (MWh)	36,648.5	213,379.7	116,750.1	52,710.4	45,841.8	7,204.4	-	5,258.0	61,779.2	161,166.0	42,523.4	187,595.0	930,856.5
Revenue Including Transmission Costs ($ x 1000)	$ 1,374.8	$ 7,458.0	$ 3,600.6	$ 1,580.3	$ 1,222.7	$ 185.6	$ -	$ 147.7	$ 1,928.4	$ 6,257.3	$ 1,770.5	$ 8,481.6	$ 34,007.5
Transmission Costs ($ x 1000)	$ 36.6	$ 213.4	$ 116.8	$ 52.7	$ 45.8	$ 7.2	$ -	$ 5.3	$ 61.8	$ 161.2	$ 42.5	$ 187.6	$ 930.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,338.1	$ 7,244.6	$ 3,483.8	$ 1,527.6	$ 1,176.9	$ 178.4	$ -	$ 142.5	$ 1,866.6	$ 6,096.1	$ 1,728.0	$ 8,294.0	$ 33,076.6
Net Power Supply Expenses ($ x 1000)	$ 16,982.3	$ 6,083.3	$ 8,946.9	$ 9,625.1	$ 8,686.6	$ 14,976.0	$ 31,538.6	$ 31,779.5	$ 17,650.7	$ 11,179.8	$ 17,136.5	$ 11,222.2	$ 185,807.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1956

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,196,275.9	1,105,051.3	1,165,561.4	969,836.1	1,029,495.2	1,310,707.2	674,157.7	664,477.2	615,244.3	528,860.7	521,893.6	854,759.8	10,636,320.5
Bridger													
Energy (MWh)	118,506.3	43,674.6	18,788.1	17,511.8	-	-	281,415.8	330,531.9	256,434.1	389,114.6	401,110.7	456,632.1	2,313,719.9
Cost ($ x 1000)	$ 2,774.0	$ 1,000.7	$ 436.1	$ 410.5	$ -	$ -	$ 6,389.5	$ 7,425.7	$ 5,789.8	$ 8,665.5	$ 8,891.5	$ 10,079.6	$ 51,862.9
Boardman													
Energy (MWh)	22,174.7	23,701.0	21,393.3	8,032.5	-	3,566.5	34,782.7	39,136.2	36,450.3	34,974.7	34,608.0	36,668.1	295,487.8
Cost ($ x 1000)	$ 423.3	$ 448.6	$ 413.9	$ 158.8	$ -	$ 69.0	$ 624.4	$ 694.2	$ 650.0	$ 630.4	$ 621.8	$ 656.4	$ 5,390.8
Valmy													
Energy (MWh)	-	-	-	-	-	-	12,056.7	-	-	25,557.6	12,199.1	79,838.5	129,651.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 435.9	$ -	$ -	$ 893.6	$ 423.5	$ 2,741.5	$ 4,494.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	708.2	366.0	15.4	191.6	0.7	-	1,281.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 25.1	$ 13.3	$ 0.6	$ 7.1	$ 0.0	$ -	$ 46.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 475.8	$ 464.1	$ 437.7	$ 458.2	$ 437.5	$ 451.5	$ 5,107.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	11.0	-	8.0	-	-	19.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4	$ -	$ 0.3	$ -	$ -	$ 0.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4	$ -	$ 0.3	$ -	$ -	$ 0.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	8,050.5	2,055.8	-	6,056.4	101,644.3	29,783.3	525,881.3	349,448.7	235,701.2	40,749.7	60,663.1	11,271.1	1,371,305.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	41,792.2	31,615.1	28,374.5	36,236.0	130,936.5	92,072.5	588,314.0	411,654.5	261,034.8	71,219.9	94,608.7	50,356.5	1,838,215.2
Market Cost ($ x 1000)	$ 218.5	$ 54.9	$ -	$ 141.0	$ 2,048.2	$ 563.3	$ 14,472.3	$ 10,449.3	$ 7,144.3	$ 1,274.6	$ 1,883.8	$ 301.6	$ 38,551.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,061.3	$ 1,670.8	$ 1,142.4	$ 1,352.1	$ 3,226.1	$ 5,218.7	$ 19,453.8	$ 15,453.1	$ 8,530.8	$ 2,940.7	$ 4,109.0	$ 2,861.1	$ 68,020.0
Surplus Sales													
Energy (MWh)	130,455.7	151,162.8	205,816.9	105,381.0	27,953.5	159,457.1	-	964.4	12,014.9	58,935.3	22,261.7	217,455.9	1,091,859.2
Revenue Including Transmission Costs ($ x 1000)	$ 2,994.3	$ 3,356.8	$ 3,998.6	$ 1,727.0	$ 396.7	$ 1,431.3	$ -	$ 22.4	$ 297.2	$ 1,813.8	$ 726.7	$ 7,837.1	$ 24,602.1
Transmission Costs ($ x 1000)	$ 130.5	$ 151.2	$ 205.8	$ 105.4	$ 28.0	$ 159.5	$ -	$ 1.0	$ 12.0	$ 58.9	$ 22.3	$ 217.5	$ 1,091.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,863.8	$ 3,205.6	$ 3,792.8	$ 1,621.6	$ 368.7	$ 1,271.9	$ -	$ 21.5	$ 285.2	$ 1,754.9	$ 704.4	$ 7,619.7	$ 23,510.2
Net Power Supply Expenses ($ x 1000)	$ 2,740.6	$ 229.0	$ (1,401.4)	$ 736.1	$ 3,307.7	$ 4,452.5	$ 27,379.5	$ 24,016.1	$ 15,123.0	$ 11,833.8	$ 13,778.8	$ 9,170.3	$ 111,366.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1957

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	851,202.1	1,088,319.8	1,106,932.0	1,147,519.7	1,230,763.6	1,250,231.2	653,493.3	568,850.0	641,449.2	539,554.6	513,763.8	813,884.0	10,405,963.3
Bridger													
Energy (MWh)	373,576.8	325,916.1	121,354.0	106,613.9	13,341.0	-	345,152.3	413,990.4	361,756.1	422,115.8	437,892.7	481,342.2	3,403,051.1
Cost ($ x 1000)	$ 8,338.8	$ 7,293.7	$ 2,803.2	$ 2,466.5	$ 312.0	$ -	$ 7,743.8	$ 9,223.7	$ 8,072.1	$ 9,357.3	$ 9,674.0	$ 10,575.6	$ 75,860.8
Boardman													
Energy (MWh)	29,230.4	26,963.3	27,397.4	13,085.2	-	17,294.2	38,968.2	38,947.7	36,790.0	36,940.2	35,091.0	38,754.2	339,461.8
Cost ($ x 1000)	$ 542.5	$ 498.6	$ 514.4	$ 246.3	$ -	$ 329.1	$ 691.6	$ 691.3	$ 655.2	$ 660.5	$ 629.2	$ 688.3	$ 6,146.8
Valmy													
Energy (MWh)	-	-	-	-	-	-	28,352.1	83,017.0	-	128,008.8	132,941.1	149,897.6	522,216.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 990.2	$ 2,841.9	$ -	$ 4,343.5	$ 4,499.8	$ 5,058.5	$ 17,733.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,394.3	2,147.5	10.8	564.4	-	-	5,116.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 98.1	$ 90.2	$ 0.4	$ 24.0	$ -	$ -	$ 212.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 548.7	$ 541.1	$ 437.6	$ 475.2	$ 437.5	$ 451.5	$ 5,274.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	42.7	-	-	67.2	-	-	109.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.8	$ -	$ -	$ 2.9	$ -	$ -	$ 4.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.8	$ -	$ -	$ 2.9	$ -	$ -	$ 4.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	62,590.0	-	1,117.8	-	9,908.2	35,655.2	460,591.8	277,717.3	124,721.3	9,945.1	6,514.6	788.7	989,549.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	96,331.7	29,559.2	29,492.3	30,179.5	39,200.3	97,944.4	523,024.5	339,923.1	150,054.8	40,415.3	40,460.2	39,874.0	1,456,459.5
Market Cost ($ x 1000)	$ 1,704.4	$ -	$ 32.7	$ -	$ 249.0	$ 873.1	$ 15,047.6	$ 9,578.2	$ 4,371.7	$ 332.9	$ 176.8	$ 21.7	$ 32,388.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,547.2	$ 1,615.9	$ 1,175.1	$ 1,211.1	$ 1,427.0	$ 5,528.6	$ 20,029.1	$ 14,581.9	$ 5,758.2	$ 1,999.0	$ 2,402.0	$ 2,581.2	$ 61,856.3
Surplus Sales													
Energy (MWh)	102,066.4	417,884.4	256,885.6	371,172.2	150,823.8	118,601.1	-	1,657.5	32,876.9	176,665.3	117,982.0	262,952.1	2,009,567.3
Revenue Including Transmission Costs ($ x 1000)	$ 3,208.7	$ 11,458.1	$ 6,111.3	$ 8,264.9	$ 2,411.3	$ 1,526.7	$ -	$ 42.1	$ 894.8	$ 6,210.0	$ 4,401.6	$ 10,882.2	$ 55,411.5
Transmission Costs ($ x 1000)	$ 102.1	$ 417.9	$ 256.9	$ 371.2	$ 150.8	$ 118.6	$ -	$ 1.7	$ 32.9	$ 176.7	$ 118.0	$ 263.0	$ 2,009.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,106.6	$ 11,040.2	$ 5,854.4	$ 7,893.7	$ 2,260.4	$ 1,408.1	$ -	$ 40.4	$ 861.9	$ 6,033.3	$ 4,283.7	$ 10,619.2	$ 53,401.9
Net Power Supply Expenses ($ x 1000)	$ 9,667.7	$ (1,317.6)	$ (962.7)	$ (3,533.5)	$ (71.1)	$ 4,886.2	$ 30,005.2	$ 27,839.4	$ 14,061.2	$ 10,805.1	$ 13,358.7	$ 8,735.9	$ 113,474.6

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1958

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	752,172.7	1,083,504.9	1,010,534.1	1,015,438.3	1,278,914.1	1,152,928.4	648,042.4	554,048.6	552,663.9	513,668.7	406,540.0	571,284.8	9,539,741.0
Bridger													
Energy (MWh)	374,469.5	264,300.4	150,569.1	33,457.1	13,672.2	15,478.4	361,274.6	407,856.7	347,482.1	420,240.9	423,998.9	473,608.5	3,286,408.4
Cost ($ x 1000)	$ 8,362.0	$ 5,926.8	$ 3,456.0	$ 774.8	$ 318.7	$ 355.8	$ 8,098.1	$ 9,100.6	$ 7,741.3	$ 9,319.7	$ 9,395.1	$ 10,420.3	$ 73,269.2
Boardman													
Energy (MWh)	29,672.6	25,461.9	28,719.8	13,749.7	-	22,480.9	40,407.0	38,298.2	36,265.2	35,616.8	32,252.1	35,276.8	338,201.0
Cost ($ x 1000)	$ 549.2	$ 475.6	$ 534.6	$ 256.4	$ -	$ 417.7	$ 713.6	$ 681.3	$ 647.1	$ 640.3	$ 585.7	$ 635.1	$ 6,136.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	30,074.8	76,891.5	-	124,236.7	128,437.9	147,536.9	507,177.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,044.2	$ 2,636.3	$ -	$ 4,215.3	$ 4,350.9	$ 4,983.5	$ 17,230.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,313.6	2,436.6	178.1	249.0	-	-	6,177.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 135.4	$ 102.1	$ 7.4	$ 10.6	$ -	$ -	$ 255.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 586.1	$ 553.0	$ 444.5	$ 461.8	$ 437.5	$ 451.5	$ 5,316.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	421.0	26.4	-	26.8	-	-	474.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.4	$ 1.1	$ -	$ 1.2	$ -	$ -	$ 19.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.4	$ 1.1	$ -	$ 1.2	$ -	$ -	$ 19.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	94,302.8	240.1	3,390.4	809.4	7,599.2	49,961.0	445,459.0	304,272.7	205,743.5	13,758.0	51,191.8	46,783.7	1,223,511.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	128,044.6	29,799.3	31,764.9	30,989.0	36,891.3	112,250.2	507,891.7	366,478.5	231,077.0	44,228.2	85,137.4	85,869.1	1,690,421.3
Market Cost ($ x 1000)	$ 2,567.1	$ 7.6	$ 98.5	$ 22.7	$ 180.9	$ 1,302.0	$ 14,654.0	$ 10,363.4	$ 7,056.4	$ 428.6	$ 1,489.2	$ 1,490.8	$ 39,661.3
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,410.0	$ 1,623.5	$ 1,240.8	$ 1,233.8	$ 1,358.9	$ 5,957.5	$ 19,635.5	$ 15,367.2	$ 8,442.9	$ 2,094.7	$ 3,714.4	$ 4,050.3	$ 69,129.5
Surplus Sales													
Energy (MWh)	36,088.9	350,191.6	193,306.1	167,422.9	196,990.5	56,294.0	-	815.8	10,486.1	147,265.8	34,196.1	52,771.8	1,245,829.6
Revenue Including Transmission Costs ($ x 1000)	$ 1,154.3	$ 9,560.4	$ 4,873.2	$ 3,832.8	$ 2,839.5	$ 917.7	$ -	$ 20.6	$ 271.0	$ 5,221.0	$ 1,267.3	$ 2,200.7	$ 32,158.5
Transmission Costs ($ x 1000)	$ 36.1	$ 350.2	$ 193.3	$ 167.4	$ 197.0	$ 56.3	$ -	$ 0.8	$ 10.5	$ 147.3	$ 34.2	$ 52.8	$ 1,245.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,118.2	$ 9,210.2	$ 4,679.8	$ 3,665.4	$ 2,642.6	$ 861.4	$ -	$ 19.7	$ 260.5	$ 5,073.8	$ 1,233.1	$ 2,148.0	$ 30,912.7
Net Power Supply Expenses ($ x 1000)	$ 12,548.7	$ (870.0)	$ 950.7	$ (964.0)	$ (514.7)	$ 6,306.3	$ 30,094.9	$ 28,319.8	$ 17,015.5	$ 11,659.0	$ 17,250.5	$ 18,392.8	$ 140,189.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1959

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	696,307.0	876,375.7	745,988.6	843,016.8	684,802.1	768,103.1	596,046.2	517,247.8	562,712.3	516,370.3	404,832.1	570,634.0	7,782,435.8
Bridger													
Energy (MWh)	377,327.3	335,628.2	324,209.3	235,678.0	252,519.1	159,687.2	398,668.3	443,303.0	375,905.3	404,409.2	418,220.1	480,259.3	4,205,814.3
Cost ($ x 1000)	$ 8,420.6	$ 7,518.2	$ 7,264.4	$ 5,301.9	$ 5,662.0	$ 3,619.9	$ 8,899.0	$ 9,812.1	$ 8,381.9	$ 9,020.4	$ 9,279.1	$ 10,553.8	$ 93,733.3
Boardman													
Energy (MWh)	24,282.2	25,070.7	29,259.9	13,426.9	-	14,466.7	36,354.3	37,580.8	31,656.6	29,577.7	30,144.4	36,030.0	307,850.3
Cost ($ x 1000)	$ 456.9	$ 469.6	$ 542.9	$ 251.5	$ -	$ 281.3	$ 651.6	$ 670.4	$ 576.6	$ 547.8	$ 553.4	$ 646.6	$ 5,648.4
Valmy													
Energy (MWh)	19,898.6	-	-	-	-	-	64,510.3	121,843.9	45,021.3	125,029.5	131,571.9	157,043.8	664,919.2
Cost ($ x 1000)	$ 690.6	$ -	$ -	$ -	$ -	$ -	$ 2,203.6	$ 4,143.1	$ 1,543.5	$ 4,245.1	$ 4,457.1	$ 5,285.4	$ 22,568.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	1,042.0	3,393.1	-	-	-	-	4,435.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 48.5	$ 162.1	$ -	$ -	$ -	$ -	$ 210.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 499.2	$ 612.9	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,271.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	35.7	-	-	-	-	35.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.7	$ -	$ -	$ -	$ -	$ 1.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.7	$ -	$ -	$ -	$ -	$ 1.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	127,955.0	5,715.4	41,842.0	12,820.9	179,744.5	243,604.5	432,398.1	263,145.5	135,305.5	24,916.1	55,676.8	30,275.0	1,553,399.2
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	161,696.7	35,274.7	70,216.5	43,000.4	209,036.6	305,893.7	494,830.9	325,351.4	160,639.0	55,386.3	89,622.4	69,360.3	2,020,308.9
Market Cost ($ x 1000)	$ 3,198.2	$ 135.7	$ 1,204.8	$ 363.8	$ 5,165.0	$ 5,617.6	$ 14,915.9	$ 10,257.0	$ 4,774.7	$ 637.3	$ 1,549.0	$ 1,126.8	$ 48,945.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 5,041.0	$ 1,751.5	$ 2,347.2	$ 1,574.9	$ 6,342.9	$ 10,273.0	$ 19,897.4	$ 15,260.7	$ 6,161.2	$ 2,303.4	$ 3,774.2	$ 3,686.3	$ 78,413.8
Surplus Sales													
Energy (MWh)	31,210.2	219,462.8	141,388.9	208,906.0	13,922.8	1,293.4	-	3,526.7	18,725.7	139,737.2	32,202.4	52,520.8	862,896.9
Revenue Including Transmission Costs ($ x 1000)	$ 1,045.6	$ 6,724.5	$ 4,127.8	$ 5,668.2	$ 288.0	$ 21.7	$ -	$ 97.0	$ 492.1	$ 5,169.7	$ 1,280.9	$ 2,430.3	$ 27,345.9
Transmission Costs ($ x 1000)	$ 31.2	$ 219.5	$ 141.4	$ 208.9	$ 13.9	$ 1.3	$ -	$ 3.5	$ 18.7	$ 139.7	$ 32.2	$ 52.5	$ 862.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,014.4	$ 6,505.1	$ 3,986.4	$ 5,459.3	$ 274.1	$ 20.4	$ -	$ 93.5	$ 473.3	$ 5,030.0	$ 1,248.7	$ 2,377.8	$ 26,483.0
Net Power Supply Expenses ($ x 1000)	$ 13,940.5	$ 3,548.7	$ 6,567.2	$ 2,105.3	$ 12,181.2	$ 14,590.5	$ 32,150.7	$ 30,407.4	$ 16,626.8	$ 11,537.8	$ 17,252.6	$ 18,245.9	$ 179,154.6

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1960

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	627,505.4	814,934.0	931,096.2	845,830.3	831,857.4	828,529.2	576,421.4	517,678.3	486,946.9	508,798.7	404,164.2	496,955.2	7,870,717.3
Bridger													
Energy (MWh)	417,929.3	352,875.3	254,913.6	116,128.6	199,873.3	135,884.0	392,943.8	428,091.9	398,416.6	434,859.5	448,550.0	482,941.3	4,063,407.0
Cost ($ x 1000)	$ 9,302.8	$ 7,893.8	$ 5,772.8	$ 2,659.9	$ 4,500.3	$ 3,107.8	$ 8,786.6	$ 9,506.8	$ 8,866.9	$ 9,627.8	$ 9,887.9	$ 10,607.6	$ 90,521.0
Boardman													
Energy (MWh)	29,280.5	26,089.3	27,549.3	10,048.2	-	19,038.5	37,420.8	37,327.1	36,315.8	36,071.9	34,689.9	39,377.9	333,209.4
Cost ($ x 1000)	$ 543.2	$ 485.2	$ 516.7	$ 192.6	$ -	$ 358.1	$ 667.9	$ 666.5	$ 647.9	$ 647.2	$ 623.0	$ 697.9	$ 6,046.2
Valmy													
Energy (MWh)	6,619.9	-	-	-	-	-	54,854.0	111,020.3	55,998.0	140,356.2	139,667.7	164,148.2	672,664.2
Cost ($ x 1000)	$ 229.4	$ -	$ -	$ -	$ -	$ -	$ 1,878.1	$ 3,776.1	$ 1,918.3	$ 4,749.6	$ 4,719.1	$ 5,511.1	$ 22,781.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,134.1	3,390.6	110.8	-	-	-	5,635.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 94.5	$ 154.1	$ 5.0	$ -	$ -	$ -	$ 253.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 545.2	$ 604.9	$ 442.1	$ 451.2	$ 437.5	$ 451.5	$ 5,314.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	4.3	28.8	-	-	-	-	33.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.2	$ 1.3	$ -	$ -	$ -	$ -	$ 1.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.2	$ 1.3	$ -	$ -	$ -	$ -	$ 1.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	145,976.3	4,975.0	11,394.3	28,817.9	111,107.8	207,342.0	465,230.0	287,899.3	169,671.3	7,834.6	20,614.2	56,315.2	1,517,177.9
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	179,718.1	34,534.2	39,768.8	58,997.4	140,400.0	269,631.3	527,662.7	350,105.2	195,004.8	38,304.8	54,559.8	95,400.6	1,984,087.6
Market Cost ($ x 1000)	$ 4,230.6	$ 128.5	$ 332.6	$ 751.0	$ 3,112.9	$ 5,028.4	$ 15,884.4	$ 10,512.4	$ 6,236.6	$ 246.3	$ 658.2	$ 2,468.6	$ 49,590.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 6,073.5	$ 1,744.4	$ 1,474.9	$ 1,962.2	$ 4,290.8	$ 9,683.8	$ 20,865.9	$ 15,516.2	$ 7,623.1	$ 1,912.4	$ 2,883.4	$ 5,028.1	$ 79,058.7
Surplus Sales													
Energy (MWh)	12,772.0	175,558.3	225,043.6	104,776.8	39,709.2	6,248.8	-	2,414.8	15,605.4	167,382.8	39,461.7	18,032.2	807,005.5
Revenue Including Transmission Costs ($ x 1000)	$ 420.8	$ 5,459.3	$ 6,117.2	$ 2,522.5	$ 991.9	$ 156.8	$ -	$ 66.7	$ 444.9	$ 6,199.0	$ 1,530.9	$ 797.6	$ 24,707.7
Transmission Costs ($ x 1000)	$ 12.8	$ 175.6	$ 225.0	$ 104.8	$ 39.7	$ 6.2	$ -	$ 2.4	$ 15.6	$ 167.4	$ 39.5	$ 18.0	$ 807.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 408.0	$ 5,283.7	$ 5,892.2	$ 2,417.8	$ 952.2	$ 150.5	$ -	$ 64.2	$ 429.3	$ 6,031.6	$ 1,491.5	$ 779.6	$ 23,900.7
Net Power Supply Expenses ($ x 1000)	$ 16,086.6	$ 5,154.2	$ 2,271.3	$ 2,833.2	$ 8,289.2	$ 13,435.8	$ 32,743.9	$ 30,007.5	$ 19,068.9	$ 11,356.6	$ 17,059.4	$ 21,516.6	$ 179,823.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1961

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,384.5	641,850.0	587,016.5	483,106.9	738,823.8	740,486.2	543,536.2	462,408.7	444,082.5	495,264.1	406,780.3	506,945.9	6,570,685.6
Bridger													
Energy (MWh)	438,845.7	360,994.9	372,230.8	320,891.3	276,400.0	233,596.3	440,578.9	466,437.1	427,025.7	447,843.8	458,888.2	483,216.7	4,726,949.3
Cost ($ x 1000)	$ 9,722.6	$ 8,056.8	$ 8,311.8	$ 7,169.5	$ 6,197.6	$ 5,263.5	$ 9,757.4	$ 10,276.4	$ 9,441.1	$ 9,903.2	$ 10,095.4	$ 10,613.2	$ 104,808.5
Boardman													
Energy (MWh)	29,842.7	24,093.3	28,794.9	13,950.3	-	8,590.4	37,992.7	38,052.9	36,658.3	36,038.1	36,567.8	39,543.9	330,125.4
Cost ($ x 1000)	$ 551.8	$ 454.6	$ 535.8	$ 259.5	$ -	$ 169.4	$ 676.7	$ 677.6	$ 653.2	$ 646.7	$ 651.8	$ 700.4	$ 5,977.5
Valmy													
Energy (MWh)	119,564.2	64,693.5	6,113.0	-	-	-	111,611.3	146,464.4	123,590.2	146,413.8	151,676.4	166,796.4	1,036,923.2
Cost ($ x 1000)	$ 4,053.5	$ 2,201.0	$ 216.9	$ -	$ -	$ -	$ 3,790.0	$ 4,949.5	$ 4,207.8	$ 4,947.6	$ 5,105.2	$ 5,595.3	$ 35,066.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	4,419.3	6,048.1	864.9	-	-	-	11,332.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 221.0	$ 310.3	$ 43.9	$ -	$ -	$ -	$ 575.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 671.6	$ 761.1	$ 481.0	$ 451.2	$ 437.5	$ 451.5	$ 5,636.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	150.3	290.3	-	-	-	-	440.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.6	$ 15.1	$ -	$ -	$ -	$ -	$ 22.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.6	$ 15.1	$ -	$ -	$ -	$ -	$ 22.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	116,558.8	39,865.8	65,159.6	103,347.8	116,595.8	207,410.6	390,719.7	272,567.9	143,672.9	2,741.1	7,510.4	46,398.9	1,512,549.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	150,300.5	69,425.0	93,534.1	133,527.3	145,888.0	269,699.9	453,152.4	334,773.8	169,006.4	33,211.3	41,456.0	85,484.3	1,979,459.0
Market Cost ($ x 1000)	$ 3,439.8	$ 922.2	$ 1,796.1	$ 2,908.7	$ 3,468.2	$ 4,908.8	$ 15,474.4	$ 11,811.9	$ 6,260.9	$ 81.7	$ 326.0	$ 2,213.2	$ 53,612.0
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 5,282.7	$ 2,538.1	$ 2,938.5	$ 4,119.8	$ 4,646.2	$ 9,564.3	$ 20,456.0	$ 16,815.7	$ 7,647.4	$ 1,747.8	$ 2,551.2	$ 4,772.7	$ 83,080.2
Surplus Sales													
Energy (MWh)	10,651.0	108,172.3	59,397.2	25,262.9	28,666.6	5,511.3	-	9,248.0	44,041.2	167,754.0	53,200.3	21,190.2	533,094.9
Revenue Including Transmission Costs ($ x 1000)	$ 402.6	$ 3,799.1	$ 1,810.2	$ 748.8	$ 633.6	$ 145.6	$ -	$ 269.7	$ 1,372.3	$ 6,708.3	$ 2,276.8	$ 1,025.5	$ 19,192.5
Transmission Costs ($ x 1000)	$ 10.7	$ 108.2	$ 59.4	$ 25.3	$ 28.7	$ 5.5	$ -	$ 9.2	$ 44.0	$ 167.8	$ 53.2	$ 21.2	$ 533.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 391.9	$ 3,691.0	$ 1,750.8	$ 723.5	$ 605.0	$ 140.1	$ -	$ 260.4	$ 1,328.2	$ 6,540.5	$ 2,223.6	$ 1,004.3	$ 18,659.4
Net Power Supply Expenses ($ x 1000)	$ 19,564.4	$ 9,874.0	$ 10,651.2	$ 11,261.6	$ 10,689.1	$ 15,293.7	$ 35,359.3	$ 33,234.9	$ 21,102.3	$ 11,156.0	$ 16,617.4	$ 21,128.8	$ 215,932.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1962

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,362.1	710,856.4	590,944.2	1,143,060.2	919,275.2	891,448.5	610,776.6	517,077.7	578,777.7	511,901.0	404,086.7	727,314.2	8,125,880.5
Bridger													
Energy (MWh)	439,756.9	384,671.8	324,920.3	147,945.4	176,034.6	149,084.4	404,159.1	429,359.5	389,585.1	434,032.8	436,106.3	478,991.9	4,194,648.1
Cost ($ x 1000)	$ 9,740.9	$ 8,546.8	$ 7,270.1	$ 3,357.5	$ 3,964.6	$ 3,395.5	$ 9,023.6	$ 9,532.2	$ 8,660.1	$ 9,626.0	$ 9,638.1	$ 10,528.4	$ 93,283.9
Boardman													
Energy (MWh)	30,358.7	28,035.4	32,812.2	12,924.8	-	20,681.0	38,649.6	37,216.7	36,500.7	34,680.1	32,245.0	35,474.1	339,578.4
Cost ($ x 1000)	$ 559.7	$ 515.0	$ 597.3	$ 243.8	$ -	$ 387.1	$ 686.7	$ 664.8	$ 650.7	$ 625.9	$ 585.6	$ 638.1	$ 6,154.7
Valmy													
Energy (MWh)	31,373.1	13,263.5	-	-	-	-	67,050.2	110,058.6	54,693.2	137,841.0	138,350.3	152,864.5	705,494.4
Cost ($ x 1000)	$ 1,081.4	$ 460.7	$ -	$ -	$ -	$ -	$ 2,291.7	$ 3,742.8	$ 1,871.6	$ 4,672.1	$ 4,682.0	$ 5,152.7	$ 23,955.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	877.1	2,392.1	-	-	-	-	3,269.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 39.2	$ 109.7	$ -	$ -	$ -	$ -	$ 148.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 489.9	$ 560.5	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,210.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	7.7	-	-	-	-	7.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4	$ -	$ -	$ -	$ -	$ 0.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4	$ -	$ -	$ -	$ -	$ 0.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	193,525.9	12,701.3	103,147.6	280.0	76,367.8	139,711.4	407,489.6	290,138.9	112,581.1	7,342.1	38,763.4	9,730.6	1,391,779.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	227,267.6	42,260.6	131,522.1	30,459.5	105,660.0	202,000.6	469,922.4	352,344.7	137,914.7	37,812.3	72,709.0	48,816.0	1,858,689.4
Market Cost ($ x 1000)	$ 6,052.9	$ 323.7	$ 3,181.2	$ 8.6	$ 2,174.7	$ 3,544.4	$ 14,328.0	$ 10,618.4	$ 4,193.9	$ 204.2	$ 1,217.4	$ 275.0	$ 46,122.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 7,895.7	$ 1,939.6	$ 4,323.5	$ 1,219.7	$ 3,352.7	$ 8,199.9	$ 19,309.5	$ 15,622.2	$ 5,580.4	$ 1,870.3	$ 3,442.6	$ 2,834.5	$ 75,590.7
Surplus Sales													
Energy (MWh)	845.3	126,223.0	51,933.8	408,155.8	68,542.2	16,387.1	-	3,227.2	40,282.9	165,254.1	41,321.2	182,652.5	1,104,825.1
Revenue Including Transmission Costs ($ x 1000)	$ 30.5	$ 4,143.3	$ 1,524.3	$ 9,409.1	$ 1,742.4	$ 407.6	$ -	$ 88.5	$ 1,180.8	$ 6,116.3	$ 1,619.2	$ 8,071.1	$ 34,333.2
Transmission Costs ($ x 1000)	$ 0.8	$ 126.2	$ 51.9	$ 408.2	$ 68.5	$ 16.4	$ -	$ 3.2	$ 40.3	$ 165.3	$ 41.3	$ 182.7	$ 1,104.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 29.7	$ 4,017.1	$ 1,472.3	$ 9,000.9	$ 1,673.9	$ 391.2	$ -	$ 85.3	$ 1,140.5	$ 5,951.0	$ 1,577.9	$ 7,888.5	$ 33,228.4
Net Power Supply Expenses ($ x 1000)	$ 19,593.9	$ 7,759.5	$ 11,117.7	$ (3,743.6)	$ 6,093.8	$ 12,027.8	$ 31,801.5	$ 30,037.5	$ 16,059.5	$ 11,294.4	$ 17,207.9	$ 11,716.7	$ 170,966.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1963

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	790,136.7	1,073,955.5	662,293.3	959,097.8	898,638.6	935,733.2	638,036.8	523,637.3	524,164.0	512,356.6	408,503.3	555,806.3	8,482,359.4
Bridger													
Energy (MWh)	421,304.7	346,656.5	321,838.5	203,270.2	196,511.6	170,508.5	404,704.8	436,124.4	395,658.5	445,559.9	453,167.6	483,005.0	4,278,310.2
Cost ($ x 1000)	$ 9,370.5	$ 7,769.0	$ 7,205.8	$ 4,566.9	$ 4,407.0	$ 3,868.2	$ 9,025.1	$ 9,668.0	$ 8,796.8	$ 9,857.4	$ 9,980.6	$ 10,608.9	$ 95,124.1
Boardman													
Energy (MWh)	29,788.1	25,362.6	30,610.5	14,129.2	-	21,953.9	38,721.6	37,859.9	36,048.8	36,573.4	35,960.8	39,536.2	346,545.1
Cost ($ x 1000)	$ 551.0	$ 474.1	$ 563.6	$ 262.3	$ -	$ 409.6	$ 687.8	$ 674.6	$ 643.8	$ 654.9	$ 642.5	$ 700.3	$ 6,264.5
Valmy													
Energy (MWh)	18,134.6	-	-	-	-	-	72,269.2	115,365.8	59,084.8	142,013.5	145,157.1	165,204.3	717,229.3
Cost ($ x 1000)	$ 621.4	$ -	$ -	$ -	$ -	$ -	$ 2,468.8	$ 3,922.8	$ 2,028.6	$ 4,804.7	$ 4,898.2	$ 5,544.7	$ 24,289.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	789.2	3,219.7	105.3	2.5	-	-	4,116.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 35.7	$ 149.6	$ 4.8	$ 0.1	$ -	$ -	$ 190.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 486.4	$ 600.4	$ 442.0	$ 451.3	$ 437.5	$ 451.5	$ 5,251.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	8.0	16.5	-	-	-	-	24.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4	$ 0.8	$ -	$ -	$ -	$ -	$ 1.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4	$ 0.8	$ -	$ -	$ -	$ -	$ 1.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	42,484.3	1,643.7	73,345.4	1,941.1	70,315.3	107,778.6	374,473.4	270,576.5	144,270.8	1,967.1	13,452.1	27,907.5	1,130,155.9
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	76,226.0	31,203.0	101,719.9	32,120.7	99,607.5	170,067.9	436,906.1	332,782.4	169,604.3	32,437.3	47,397.7	66,992.9	1,597,065.6
Market Cost ($ x 1000)	$ 1,094.2	$ 42.6	$ 2,207.2	$ 57.4	$ 1,957.0	$ 2,647.4	$ 13,317.5	$ 10,238.1	$ 5,362.2	$ 54.8	$ 468.5	$ 1,215.5	$ 38,662.4
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,937.1	$ 1,658.5	$ 3,349.6	$ 1,268.5	$ 3,135.0	$ 7,302.9	$ 18,299.0	$ 15,241.8	$ 6,748.7	$ 1,720.9	$ 2,693.7	$ 3,774.9	$ 68,130.6
Surplus Sales													
Energy (MWh)	87,308.6	424,296.2	88,189.8	282,398.6	62,333.1	51,443.3	-	3,779.5	27,473.5	177,935.5	48,020.4	49,752.3	1,302,930.8
Revenue Including Transmission Costs ($ x 1000)	$ 3,005.8	$ 12,437.3	$ 2,586.0	$ 7,256.5	$ 1,733.0	$ 1,446.6	$ -	$ 103.5	$ 797.5	$ 6,712.6	$ 1,906.6	$ 2,285.3	$ 40,270.7
Transmission Costs ($ x 1000)	$ 87.3	$ 424.3	$ 88.2	$ 282.4	$ 62.3	$ 51.4	$ -	$ 3.8	$ 27.5	$ 177.9	$ 48.0	$ 49.8	$ 1,302.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,918.5	$ 12,013.0	$ 2,497.8	$ 6,974.1	$ 1,670.7	$ 1,395.1	$ -	$ 99.8	$ 770.0	$ 6,534.7	$ 1,858.6	$ 2,235.5	$ 38,967.8
Net Power Supply Expenses ($ x 1000)	$ 10,907.4	$ (1,797.0)	$ 9,020.3	$ (440.1)	$ 6,321.6	$ 10,622.2	$ 30,967.5	$ 30,008.7	$ 17,889.8	$ 10,954.4	$ 16,793.7	$ 18,844.9	$ 160,093.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1964

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	781,761.4	868,936.2	672,681.2	1,209,024.2	835,188.6	1,214,904.3	657,399.1	621,058.8	618,281.6	496,195.6	502,950.7	1,068,768.0	9,547,149.6
Bridger													
Energy (MWh)	351,759.3	309,366.2	237,710.8	64,941.9	98,831.2	-	325,880.1	390,873.5	342,284.1	408,908.6	424,476.9	440,731.5	3,395,764.3
Cost ($ x 1000)	$ 7,874.5	$ 6,917.3	$ 5,406.6	$ 1,510.0	$ 2,267.6	$ -	$ 7,320.1	$ 8,735.2	$ 7,643.2	$ 9,107.0	$ 9,390.0	$ 9,760.5	$ 75,931.8
Boardman													
Energy (MWh)	28,465.7	27,220.4	31,744.1	13,525.8	-	5,351.2	36,759.9	37,819.6	35,583.1	33,332.1	33,791.5	32,201.1	315,794.4
Cost ($ x 1000)	$ 530.7	$ 502.5	$ 581.0	$ 253.0	$ -	$ 106.4	$ 655.4	$ 674.0	$ 636.7	$ 605.3	$ 609.3	$ 588.0	$ 5,742.2
Valmy													
Energy (MWh)	-	-	-	-	-	-	5,438.4	46,538.4	5,435.0	110,190.0	131,882.8	135,727.7	435,212.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 191.9	$ 1,595.2	$ 189.0	$ 3,748.7	$ 4,467.1	$ 4,598.7	$ 14,790.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	258.8	136.8	-	-	-	-	395.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.5	$ 5.7	$ -	$ -	$ -	$ -	$ 16.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 461.2	$ 456.5	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,077.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	107,923.0	18,006.4	113,702.0	148.3	193,560.9	58,022.5	503,273.3	287,763.4	152,786.9	20,690.4	15,642.5	2,467.6	1,473,987.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	141,664.8	47,565.7	142,076.5	30,327.8	222,853.0	120,311.8	565,706.1	349,969.2	178,120.5	51,160.6	49,588.1	41,553.0	1,940,897.1
Market Cost ($ x 1000)	$ 2,955.8	$ 537.6	$ 3,324.0	$ 4.5	$ 5,372.1	$ 1,103.2	$ 15,425.7	$ 9,473.2	$ 5,089.9	$ 596.4	$ 445.7	$ 65.0	$ 44,393.2
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,798.6	$ 2,153.5	$ 4,466.4	$ 1,215.6	$ 6,550.1	$ 5,758.7	$ 20,407.2	$ 14,476.9	$ 6,476.4	$ 2,262.5	$ 2,670.9	$ 2,624.5	$ 73,861.4
Surplus Sales													
Energy (MWh)	55,376.9	200,222.2	55,956.7	391,596.4	24,462.5	93,675.2	-	1,168.3	22,520.5	108,776.7	100,521.6	458,158.0	1,512,435.1
Revenue Including Transmission Costs ($ x 1000)	$ 1,702.3	$ 5,773.8	$ 1,573.6	$ 8,666.8	$ 574.7	$ 924.1	$ -	$ 29.7	$ 610.2	$ 3,748.6	$ 3,693.2	$ 16,621.2	$ 43,918.2
Transmission Costs ($ x 1000)	$ 55.4	$ 200.2	$ 56.0	$ 391.6	$ 24.5	$ 93.7	$ -	$ 1.2	$ 22.5	$ 108.8	$ 100.5	$ 458.2	$ 1,512.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,646.9	$ 5,573.5	$ 1,517.7	$ 8,275.2	$ 550.3	$ 830.5	$ -	$ 28.5	$ 587.7	$ 3,639.8	$ 3,592.6	$ 16,163.0	$ 42,405.7
Net Power Supply Expenses ($ x 1000)	$ 11,902.8	$ 4,314.3	$ 9,335.3	$ (4,860.3)	$ 8,717.7	$ 5,471.3	$ 29,035.7	$ 25,909.3	$ 14,794.7	$ 12,534.8	$ 13,982.0	$ 1,860.1	$ 132,997.6

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1965

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,333,092.5	1,085,011.6	1,258,881.0	1,005,132.2	1,114,782.9	1,259,602.0	844,907.2	758,203.0	710,889.0	683,768.0	548,166.7	833,902.3	11,436,338.5
Bridger													
Energy (MWh)	144,499.1	133,979.1	53,908.0	33,805.4	-	-	276,413.8	328,283.7	265,132.9	374,890.6	408,741.8	475,368.3	2,495,022.8
Cost ($ x 1000)	$ 3,358.7	$ 3,116.9	$ 1,259.0	$ 796.5	$ -	$ -	$ 6,247.3	$ 7,383.1	$ 5,976.7	$ 8,352.9	$ 9,059.4	$ 10,455.6	$ 56,006.1
Boardman													
Energy (MWh)	21,446.6	18,818.3	23,370.5	9,447.5	-	12,960.3	38,109.2	36,626.5	36,024.2	34,452.4	34,170.8	38,576.4	304,002.7
Cost ($ x 1000)	$ 410.3	$ 360.8	$ 444.4	$ 183.4	$ -	$ 245.8	$ 678.4	$ 655.7	$ 643.5	$ 622.4	$ 615.1	$ 685.6	$ 5,545.4
Valmy													
Energy (MWh)	-	-	-	-	-	-	19,236.7	-	-	27,305.1	42,508.0	113,472.3	202,522.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 694.7	$ -	$ -	$ 957.2	$ 1,474.4	$ 3,884.2	$ 7,010.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	222.5	3.8	0.1	2.0	13.2	-	241.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 8.2	$ 0.1	$ 0.0	$ 0.1	$ 0.6	$ -	$ 9.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 458.8	$ 451.0	$ 437.1	$ 451.3	$ 438.0	$ 451.5	$ 5,070.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	988.1	623.5	-	1,484.0	35,835.2	31,462.3	350,247.8	263,663.7	158,403.1	21,370.1	30,920.0	3,527.7	898,525.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	34,729.9	30,182.8	28,374.5	31,663.5	65,127.3	93,751.5	412,680.6	325,869.5	183,736.6	51,840.3	64,865.5	42,613.1	1,365,435.1
Market Cost ($ x 1000)	$ 23.1	$ 17.8	$ -	$ 36.5	$ 893.7	$ 703.2	$ 10,092.9	$ 7,722.4	$ 4,896.1	$ 677.5	$ 938.7	$ 97.5	$ 26,099.4
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,865.9	$ 1,633.7	$ 1,142.4	$ 1,247.6	$ 2,071.7	$ 5,358.6	$ 15,074.4	$ 12,726.1	$ 6,282.6	$ 2,343.6	$ 3,163.9	$ 2,657.0	$ 55,567.6
Surplus Sales													
Energy (MWh)	285,466.9	215,099.7	336,234.6	153,824.4	47,471.0	119,450.9	138.7	3,756.8	38,609.2	181,256.3	56,303.8	243,137.5	1,680,749.8
Revenue Including Transmission Costs ($ x 1000)	$ 6,535.9	$ 4,744.8	$ 6,847.1	$ 2,976.9	$ 844.2	$ 1,335.7	$ 2.9	$ 97.4	$ 1,014.1	$ 5,634.5	$ 1,922.9	$ 9,134.0	$ 41,090.4
Transmission Costs ($ x 1000)	$ 285.5	$ 215.1	$ 336.2	$ 153.8	$ 47.5	$ 119.5	$ 0.1	$ 3.8	$ 38.6	$ 181.3	$ 56.3	$ 243.1	$ 1,680.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 6,250.5	$ 4,529.7	$ 6,510.9	$ 2,823.1	$ 796.8	$ 1,216.2	$ 2.8	$ 93.6	$ 975.5	$ 5,453.2	$ 1,866.6	$ 8,890.9	$ 39,409.7
Net Power Supply Expenses ($ x 1000)	$ (269.8)	$ 896.1	$ (3,266.0)	$ (159.2)	$ 1,725.2	$ 4,824.8	$ 23,151.0	$ 21,122.3	$ 12,364.4	$ 7,274.2	$ 12,884.2	$ 9,243.2	$ 89,790.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1966

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	917,099.4	784,125.7	764,390.0	820,367.2	804,464.7	753,946.8	583,354.3	497,901.2	461,654.9	523,152.7	409,595.8	528,236.1	7,848,288.7
Bridger													
Energy (MWh)	432,230.5	420,828.3	408,265.0	261,180.2	274,018.8	251,945.3	435,223.5	460,018.0	420,293.8	448,682.7	458,476.0	483,049.5	4,754,211.6
Cost ($ x 1000)	$ 9,589.8	$ 9,272.5	$ 9,079.3	$ 5,863.5	$ 6,133.2	$ 5,675.4	$ 9,638.8	$ 10,147.6	$ 9,306.0	$ 9,920.0	$ 10,087.1	$ 10,609.8	$ 105,323.1
Boardman													
Energy (MWh)	30,610.5	30,911.8	32,381.8	12,737.6	-	21,163.1	38,848.7	37,725.6	36,759.5	36,341.9	36,467.7	38,154.2	352,102.5
Cost ($ x 1000)	$ 563.6	$ 559.0	$ 590.7	$ 240.9	$ -	$ 394.4	$ 689.8	$ 672.6	$ 654.7	$ 651.4	$ 650.2	$ 679.1	$ 6,346.6
Valmy													
Energy (MWh)	88,097.3	88,394.5	1,262.6	-	-	-	112,444.7	130,420.8	110,167.1	145,132.9	149,535.7	162,952.6	988,408.2
Cost ($ x 1000)	$ 3,034.7	$ 3,037.3	$ 45.7	$ -	$ -	$ -	$ 3,832.4	$ 4,429.8	$ 3,753.8	$ 4,902.9	$ 5,037.2	$ 5,473.1	$ 33,546.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,395.8	4,463.6	370.4	-	-	-	7,229.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 116.3	$ 222.2	$ 18.2	$ -	$ -	$ -	$ 356.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 566.9	$ 673.1	$ 455.4	$ 451.2	$ 437.5	$ 451.5	$ 5,418.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	110.9	199.4	-	-	-	-	310.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.5	$ 10.1	$ -	$ -	$ -	$ -	$ 15.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.5	$ 10.1	$ -	$ -	$ -	$ -	$ 15.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	6,376.1	-	6,565.0	8,965.2	70,259.3	164,575.8	356,701.1	259,272.9	143,203.6	1,047.9	7,983.7	44,522.7	1,069,473.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	40,117.9	29,559.2	34,939.5	39,144.7	99,551.4	226,865.1	419,133.8	321,478.8	168,537.1	31,518.1	41,929.3	83,608.1	1,536,383.1
Market Cost ($ x 1000)	$ 157.1	$ -	$ 211.8	$ 241.6	$ 2,082.6	$ 4,611.0	$ 13,893.2	$ 10,764.5	$ 5,866.8	$ 30.6	$ 317.0	$ 2,005.5	$ 40,181.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,000.0	$ 1,615.9	$ 1,354.2	$ 1,452.7	$ 3,260.6	$ 9,266.4	$ 18,874.7	$ 15,768.3	$ 7,253.3	$ 1,696.7	$ 2,542.2	$ 4,565.0	$ 69,649.8
Surplus Sales													
Energy (MWh)	259,869.1	300,956.8	212,950.6	207,202.5	45,600.4	7,091.2	76.7	6,979.4	40,593.3	193,816.0	53,836.2	35,199.0	1,364,171.1
Revenue Including Transmission Costs ($ x 1000)	$ 9,297.8	$ 10,620.7	$ 6,274.7	$ 5,645.7	$ 1,133.2	$ 184.7	$ 2.1	$ 198.6	$ 1,258.0	$ 7,702.3	$ 2,240.8	$ 1,666.5	$ 46,225.0
Transmission Costs ($ x 1000)	$ 259.9	$ 301.0	$ 213.0	$ 207.2	$ 45.6	$ 7.1	$ 0.1	$ 7.0	$ 40.6	$ 193.8	$ 53.8	$ 35.2	$ 1,364.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,037.9	$ 10,319.7	$ 6,061.8	$ 5,438.5	$ 1,087.6	$ 177.6	$ 2.0	$ 191.7	$ 1,217.4	$ 7,508.4	$ 2,186.9	$ 1,631.3	$ 44,860.8
Net Power Supply Expenses ($ x 1000)	$ 6,495.9	$ 4,479.4	$ 5,407.2	$ 2,554.9	$ 8,756.5	$ 15,595.3	$ 33,606.1	$ 31,509.7	$ 20,205.7	$ 10,113.7	$ 16,567.3	$ 20,147.2	$ 175,439.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1967

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	573,494.5	889,886.7	576,232.0	858,876.2	845,716.6	1,168,472.3	673,075.5	519,531.4	607,268.2	573,894.1	532,333.2	766,302.3	8,585,083.3
Bridger													
Energy (MWh)	397,226.5	326,288.5	291,701.4	238,814.2	182,949.0	71,595.5	370,748.5	423,120.6	383,619.8	433,122.1	443,789.3	482,679.9	4,045,655.2
Cost ($ x 1000)	$ 8,857.8	$ 7,309.8	$ 6,546.8	$ 5,353.8	$ 4,134.8	$ 1,652.1	$ 8,302.4	$ 9,407.0	$ 8,540.4	$ 9,607.7	$ 9,792.3	$ 10,602.4	$ 90,107.2
Boardman													
Energy (MWh)	26,925.9	24,817.4	29,878.6	14,429.9	-	4,580.2	35,611.4	37,416.8	36,249.2	35,263.0	34,513.7	38,515.2	318,201.3
Cost ($ x 1000)	$ 504.1	$ 465.7	$ 552.4	$ 266.9	$ -	$ 92.2	$ 640.2	$ 667.8	$ 646.9	$ 634.9	$ 620.3	$ 684.7	$ 5,776.0
Valmy													
Energy (MWh)	-	-	-	-	-	-	23,229.0	107,253.3	42,371.5	132,094.4	137,549.0	157,607.0	600,104.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 797.3	$ 3,649.5	$ 1,453.6	$ 4,477.2	$ 4,651.7	$ 5,303.2	$ 20,332.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	112.0	2,555.7	-	1.5	-	-	2,669.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.9	$ 115.4	$ -	$ 0.1	$ -	$ -	$ 120.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 455.6	$ 566.2	$ 437.1	$ 451.3	$ 437.5	$ 451.5	$ 5,181.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	220,901.6	8,372.2	134,670.2	7,905.0	123,759.0	44,190.4	426,248.0	296,446.8	109,620.5	2,921.8	2,858.1	1,178.0	1,379,071.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	254,643.4	37,931.5	163,044.7	38,084.5	153,051.1	106,479.7	488,680.7	358,652.6	134,954.0	33,392.0	36,803.6	40,263.4	1,845,981.3
Market Cost ($ x 1000)	$ 6,282.6	$ 215.6	$ 3,925.9	$ 235.2	$ 3,529.9	$ 812.9	$ 13,630.5	$ 10,634.5	$ 3,961.0	$ 79.0	$ 77.5	$ 34.1	$ 43,418.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 8,125.5	$ 1,831.4	$ 5,068.2	$ 1,446.3	$ 4,707.8	$ 5,468.4	$ 18,612.1	$ 15,638.2	$ 5,347.5	$ 1,745.1	$ 2,302.7	$ 2,593.6	$ 72,886.8
Surplus Sales													
Energy (MWh)	4,004.8	226,044.1	32,590.7	224,008.2	49,288.1	104,231.9	-	3,300.9	47,270.2	216,754.6	142,816.1	224,567.6	1,274,877.2
Revenue Including Transmission Costs ($ x 1000)	$ 126.6	$ 6,610.9	$ 975.6	$ 6,183.2	$ 1,154.0	$ 1,553.1	$ -	$ 88.9	$ 1,353.4	$ 7,862.5	$ 5,519.1	$ 9,910.2	$ 41,337.3
Transmission Costs ($ x 1000)	$ 4.0	$ 226.0	$ 32.6	$ 224.0	$ 49.3	$ 104.2	$ -	$ 3.3	$ 47.3	$ 216.8	$ 142.8	$ 224.6	$ 1,274.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 122.6	$ 6,384.9	$ 943.0	$ 5,959.2	$ 1,104.7	$ 1,448.9	$ -	$ 85.6	$ 1,306.1	$ 7,645.7	$ 5,376.3	$ 9,685.6	$ 40,062.5
Net Power Supply Expenses ($ x 1000)	$ 17,710.5	$ 3,536.6	$ 11,623.5	$ 1,544.1	$ 8,188.2	$ 6,200.4	$ 28,807.5	$ 29,843.2	$ 15,119.4	$ 9,270.4	$ 12,428.3	$ 9,949.7	$ 154,221.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1968

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	772,192.0	892,536.1	917,326.0	759,857.6	807,967.9	802,456.5	577,007.2	582,628.6	615,330.3	496,561.9	527,578.1	786,817.9	8,538,260.2
Bridger													
Energy (MWh)	403,181.4	357,045.2	227,986.3	240,691.0	204,918.2	139,324.6	390,389.0	424,008.7	373,197.8	421,037.3	417,373.0	478,243.1	4,077,395.4
Cost ($ x 1000)	$ 8,992.0	$ 7,992.3	$ 5,162.3	$ 5,409.6	$ 4,612.0	$ 3,185.7	$ 8,727.9	$ 9,424.8	$ 8,327.5	$ 9,354.1	$ 9,262.1	$ 10,513.3	$ 90,963.7
Boardman													
Energy (MWh)	29,064.8	26,341.2	28,113.5	14,498.3	-	19,396.3	38,061.6	37,246.1	33,775.4	33,272.8	30,561.7	36,211.3	326,543.1
Cost ($ x 1000)	$ 539.9	$ 489.0	$ 525.4	$ 267.9	$ -	$ 362.9	$ 677.7	$ 665.2	$ 609.0	$ 604.4	$ 559.8	$ 649.4	$ 5,950.6
Valmy													
Energy (MWh)	-	-	-	-	-	-	61,300.0	108,011.7	21,257.7	130,338.5	132,436.3	152,976.8	606,321.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,099.0	$ 3,675.2	$ 730.7	$ 4,419.0	$ 4,487.0	$ 5,156.2	$ 20,567.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,254.3	1,105.7	-	37.9	-	-	3,397.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 99.4	$ 50.0	$ -	$ 1.7	$ -	$ -	$ 151.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 550.1	$ 500.9	$ 437.1	$ 452.9	$ 437.5	$ 451.5	$ 5,212.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	5.4	1.9	-	-	-	-	7.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.2	$ 0.1	$ -	$ -	$ -	$ -	$ 0.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.2	$ 0.1	$ -	$ -	$ -	$ -	$ 0.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	62,628.4	145.1	20,508.4	24,535.7	131,337.0	227,298.8	459,985.9	233,549.0	118,233.0	14,213.5	19,042.0	4,032.0	1,315,508.9
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	96,370.1	29,704.4	48,882.9	54,715.2	160,629.1	289,588.1	522,418.6	295,754.8	143,566.5	44,683.7	52,987.6	43,117.4	1,782,418.6
Market Cost ($ x 1000)	$ 1,573.5	$ 3.6	$ 591.9	$ 723.6	$ 3,779.7	$ 5,794.4	$ 15,878.0	$ 8,362.7	$ 4,093.9	$ 405.4	$ 497.2	$ 112.8	$ 41,816.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,416.4	$ 1,619.4	$ 1,734.3	$ 1,934.7	$ 4,957.7	$ 10,449.9	$ 20,859.5	$ 13,366.5	$ 5,480.4	$ 2,071.4	$ 2,722.4	$ 2,672.3	$ 71,284.9
Surplus Sales													
Energy (MWh)	52,523.8	252,751.7	194,026.8	143,568.2	41,094.8	3,935.8	-	3,525.7	29,927.3	134,914.6	118,752.7	236,559.6	1,211,581.0
Revenue Including Transmission Costs ($ x 1000)	$ 1,721.6	$ 7,657.0	$ 5,322.3	$ 4,028.2	$ 997.5	$ 104.5	$ -	$ 98.8	$ 822.7	$ 4,897.3	$ 4,521.6	$ 10,285.0	$ 40,456.5
Transmission Costs ($ x 1000)	$ 52.5	$ 252.8	$ 194.0	$ 143.6	$ 41.1	$ 3.9	$ -	$ 3.5	$ 29.9	$ 134.9	$ 118.8	$ 236.6	$ 1,211.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,669.1	$ 7,404.3	$ 5,128.2	$ 3,884.6	$ 956.4	$ 100.6	$ -	$ 95.2	$ 792.8	$ 4,762.4	$ 4,402.8	$ 10,048.4	$ 39,244.9
Net Power Supply Expenses ($ x 1000)	$ 11,625.0	$ 3,011.0	$ 2,692.7	$ 4,163.8	$ 9,063.6	$ 14,334.6	$ 32,914.5	$ 27,537.4	$ 14,792.0	$ 12,139.5	$ 13,065.9	$ 9,394.3	$ 154,734.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1969

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,124,874.8	1,166,771.5	1,203,875.7	1,088,942.7	1,067,021.7	932,607.7	642,874.3	537,712.1	526,671.9	524,418.4	412,246.3	536,260.9	9,764,277.9
Bridger													
Energy (MWh)	247,448.2	248,158.2	153,799.7	27,463.7	26,877.8	15,990.7	332,245.0	400,268.0	357,267.8	429,239.2	444,777.4	480,314.7	3,163,850.3
Cost ($ x 1000)	$ 5,566.1	$ 5,564.7	$ 3,552.8	$ 648.9	$ 628.0	$ 367.0	$ 7,473.6	$ 8,933.6	$ 7,967.3	$ 9,529.8	$ 9,812.2	$ 10,554.9	$ 70,598.8
Boardman													
Energy (MWh)	25,234.0	26,135.7	28,377.2	7,205.7	-	21,483.5	38,476.9	38,432.6	36,503.3	35,705.2	35,866.6	38,788.7	332,209.5
Cost ($ x 1000)	$ 474.5	$ 485.9	$ 529.4	$ 143.5	$ -	$ 402.4	$ 684.1	$ 683.4	$ 650.8	$ 641.6	$ 641.0	$ 688.8	$ 6,025.5
Valmy													
Energy (MWh)	-	-	-	-	-	-	11,237.8	73,026.4	3,034.9	119,502.5	134,434.2	153,691.1	494,927.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 398.0	$ 2,502.8	$ 104.8	$ 4,056.0	$ 4,545.7	$ 5,179.0	$ 16,786.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	966.5	2,939.9	27.6	11.4	-	-	3,945.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 39.0	$ 121.7	$ 1.1	$ 0.5	$ -	$ -	$ 162.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 489.7	$ 572.6	$ 438.3	$ 451.7	$ 437.5	$ 451.5	$ 5,223.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	26.8	21.6	-	-	-	-	48.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.1	$ 0.9	$ -	$ -	$ -	$ -	$ 2.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.1	$ 0.9	$ -	$ -	$ -	$ -	$ 2.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	18,478.5	157.3	-	48.0	46,405.4	216,416.5	503,177.4	331,143.2	214,867.5	8,285.4	22,520.0	49,735.1	1,411,234.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	52,220.3	29,716.5	28,374.5	30,227.5	75,697.6	278,705.8	565,610.2	393,349.1	240,201.1	38,755.6	56,465.6	88,820.4	1,878,144.1
Market Cost ($ x 1000)	$ 499.8	$ 5.0	$ -	$ 1.1	$ 1,096.1	$ 4,867.4	$ 15,648.0	$ 11,211.4	$ 7,278.6	$ 222.6	$ 686.8	$ 1,932.7	$ 43,449.4
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,342.6	$ 1,620.9	$ 1,142.4	$ 1,212.2	$ 2,274.0	$ 9,522.9	$ 20,629.5	$ 16,215.1	$ 8,665.1	$ 1,888.6	$ 2,912.0	$ 4,492.2	$ 72,917.6
Surplus Sales													
Energy (MWh)	201,484.7	417,900.6	386,133.8	227,586.1	37,133.0	1,953.9	-	531.0	6,528.9	156,631.6	41,629.5	37,083.7	1,514,596.7
Revenue Including Transmission Costs ($ x 1000)	$ 5,622.4	$ 10,783.0	$ 9,043.2	$ 4,126.7	$ 705.5	$ 24.8	$ -	$ 13.4	$ 168.0	$ 5,525.6	$ 1,556.1	$ 1,493.9	$ 39,062.4
Transmission Costs ($ x 1000)	$ 201.5	$ 417.9	$ 386.1	$ 227.6	$ 37.1	$ 2.0	$ -	$ 0.5	$ 6.5	$ 156.6	$ 41.6	$ 37.1	$ 1,514.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,421.0	$ 10,365.1	$ 8,657.0	$ 3,899.1	$ 668.4	$ 22.8	$ -	$ 12.8	$ 161.4	$ 5,368.9	$ 1,514.4	$ 1,456.8	$ 37,547.8
Net Power Supply Expenses ($ x 1000)	$ 3,308.1	$ (2,379.1)	$ (3,033.4)	$ (1,458.2)	$ 2,683.9	$ 10,706.1	$ 29,676.0	$ 28,895.6	$ 17,664.7	$ 11,198.8	$ 16,833.9	$ 19,909.6	$ 134,006.0

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1970

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,079,887.0	1,103,528.0	848,781.2	1,021,338.0	1,116,262.8	1,268,202.3	786,720.2	670,424.2	622,856.4	535,340.3	524,900.7	893,563.0	10,471,804.1
Bridger													
Energy (MWh)	367,240.9	332,476.5	272,695.7	186,989.5	65,721.5	-	346,683.9	408,519.6	357,734.7	419,333.0	438,572.7	479,882.7	3,675,850.7
Cost ($ x 1000)	$ 8,218.4	$ 7,423.0	$ 6,173.9	$ 4,232.5	$ 1,496.1	$ -	$ 7,779.4	$ 9,113.9	$ 7,974.2	$ 9,289.2	$ 9,687.6	$ 10,546.3	$ 81,934.5
Boardman													
Energy (MWh)	28,860.0	27,851.4	32,789.3	14,786.5	-	17,462.7	38,984.9	38,560.7	36,649.5	36,708.5	34,917.1	38,300.8	345,871.2
Cost ($ x 1000)	$ 536.8	$ 512.2	$ 597.0	$ 272.3	$ -	$ 332.0	$ 691.9	$ 685.4	$ 653.0	$ 657.0	$ 626.5	$ 681.4	$ 6,245.4
Valmy													
Energy (MWh)	-	-	-	-	-	-	14,715.8	93,840.2	9,359.1	125,617.4	136,002.9	149,763.3	529,298.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 511.8	$ 3,218.5	$ 324.4	$ 4,259.6	$ 4,602.7	$ 5,054.1	$ 17,971.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	393.8	656.9	-	54.3	-	-	1,105.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.4	$ 28.1	$ -	$ 2.4	$ -	$ -	$ 46.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 467.1	$ 478.9	$ 437.1	$ 453.5	$ 437.5	$ 451.5	$ 5,108.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	7,453.5	2.9	26,959.9	220.4	22,306.3	29,822.5	341,586.4	179,963.2	131,562.9	12,142.1	4,317.1	123.8	756,461.0
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	41,195.2	29,562.2	55,334.4	30,399.9	51,598.4	92,111.7	404,019.2	242,169.0	156,896.5	42,612.3	38,262.6	39,209.2	1,223,370.7
Market Cost ($ x 1000)	$ 216.1	$ 0.1	$ 800.6	$ 6.8	$ 624.3	$ 720.8	$ 11,205.6	$ 6,091.3	$ 4,598.1	$ 401.1	$ 115.6	$ 3.4	$ 24,783.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,059.0	$ 1,616.0	$ 1,942.9	$ 1,218.0	$ 1,802.2	$ 5,376.2	$ 16,187.1	$ 11,095.1	$ 5,984.6	$ 2,067.2	$ 2,340.8	$ 2,562.9	$ 54,251.9
Surplus Sales													
Energy (MWh)	268,897.8	440,544.8	181,334.4	327,305.6	101,151.9	130,906.9	85.6	8,944.3	26,310.6	168,662.9	130,486.7	339,915.6	2,124,547.0
Revenue Including Transmission Costs ($ x 1000)	$ 8,001.0	$ 12,328.5	$ 5,073.5	$ 8,061.4	$ 2,385.6	$ 1,626.2	$ 2.4	$ 259.0	$ 719.8	$ 5,962.7	$ 4,868.1	$ 13,834.5	$ 63,122.5
Transmission Costs ($ x 1000)	$ 268.9	$ 440.5	$ 181.3	$ 327.3	$ 101.2	$ 130.9	$ 0.1	$ 8.9	$ 26.3	$ 168.7	$ 130.5	$ 339.9	$ 2,124.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,732.1	$ 11,888.0	$ 4,892.1	$ 7,734.1	$ 2,284.4	$ 1,495.3	$ 2.3	$ 250.1	$ 693.4	$ 5,794.1	$ 4,737.6	$ 13,494.6	$ 60,998.0
Net Power Supply Expenses ($ x 1000)	$ 3,427.9	$ (2,022.4)	$ 4,220.8	$ (1,575.0)	$ 1,464.2	$ 4,649.6	$ 25,635.0	$ 24,341.6	$ 14,679.8	$ 10,932.4	$ 12,957.5	$ 5,801.6	$ 104,512.9

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1971

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,339,410.4	1,097,729.1	1,169,613.6	957,877.5	1,212,122.3	1,258,294.2	970,255.0	708,205.2	945,286.1	780,549.1	667,749.9	970,605.5	12,077,697.7
Bridger													
Energy (MWh)	135,329.2	97,416.5	-	32,581.0	-	-	226,773.9	319,890.7	239,583.8	384,986.5	394,308.3	465,426.6	2,296,296.4
Cost ($ x 1000)	$ 3,176.2	$ 2,279.8	$ -	$ 757.2	$ -	$ -	$ 5,155.1	$ 7,201.1	$ 5,449.1	$ 8,582.6	$ 8,754.9	$ 10,256.1	$ 51,612.1
Boardman													
Energy (MWh)	23,867.5	16,702.2	19,686.6	10,709.2	-	1,079.3	35,443.2	36,914.1	35,945.7	35,489.4	33,598.5	37,857.3	287,293.1
Cost ($ x 1000)	$ 457.1	$ 324.0	$ 380.2	$ 206.8	$ -	$ 20.4	$ 634.6	$ 660.1	$ 642.3	$ 638.3	$ 606.3	$ 674.6	$ 5,244.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	9,740.0	-	-	10,624.2	4,259.0	85,560.7	110,183.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 352.4	$ -	$ -	$ 376.2	$ 147.1	$ 2,937.4	$ 3,813.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	299.2	37.8	0.6	229.0	1.0	-	567.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.6	$ 1.4	$ 0.0	$ 8.5	$ 0.0	$ -	$ 20.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 461.3	$ 452.2	$ 437.1	$ 459.6	$ 437.5	$ 451.5	$ 5,081.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	25.6	-	-	-	-	-	25.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.9	$ -	$ -	$ -	$ -	$ -	$ 0.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.9	$ -	$ -	$ -	$ -	$ -	$ 0.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	152.9	1,399.7	-	6,297.9	11,275.5	36,174.4	290,921.5	322,278.9	75,915.6	6,171.2	25,139.7	1,271.0	776,998.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	33,894.7	30,958.9	28,374.5	36,477.5	40,567.6	98,463.7	353,354.3	384,484.8	101,249.2	36,641.4	59,085.3	40,356.4	1,243,908.1
Market Cost ($ x 1000)	$ 4.4	$ 35.6	$ -	$ 162.2	$ 256.5	$ 708.4	$ 7,974.0	$ 9,311.1	$ 2,382.7	$ 186.6	$ 728.7	$ 34.1	$ 21,784.3
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,847.2	$ 1,651.5	$ 1,142.4	$ 1,373.4	$ 1,434.4	$ 5,363.8	$ 12,955.6	$ 14,314.8	$ 3,769.2	$ 1,852.7	$ 2,953.9	$ 2,593.5	$ 51,252.5
Surplus Sales													
Energy (MWh)	284,207.9	189,911.5	189,373.3	111,444.5	120,220.8	110,946.4	4,450.8	4,309.7	164,882.8	257,515.4	116,835.5	339,006.5	1,893,105.2
Revenue Including Transmission Costs ($ x 1000)	$ 6,545.4	$ 3,934.4	$ 3,636.2	$ 2,185.3	$ 1,743.2	$ 1,043.4	$ 126.0	$ 107.9	$ 3,956.3	$ 7,793.8	$ 3,729.1	$ 11,935.5	$ 46,736.6
Transmission Costs ($ x 1000)	$ 284.2	$ 189.9	$ 189.4	$ 111.4	$ 120.2	$ 110.9	$ 4.5	$ 4.3	$ 164.9	$ 257.5	$ 116.8	$ 339.0	$ 1,893.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 6,261.2	$ 3,744.5	$ 3,446.9	$ 2,073.9	$ 1,623.0	$ 932.4	$ 121.5	$ 103.6	$ 3,791.4	$ 7,536.2	$ 3,612.3	$ 11,596.5	$ 44,843.5
Net Power Supply Expenses ($ x 1000)	$ (434.8)	$ 825.2	$ (1,525.2)	$ 699.7	$ 261.7	$ 4,888.4	$ 19,438.3	$ 22,524.7	$ 6,506.3	$ 4,373.3	$ 9,287.4	$ 5,316.6	$ 72,161.7

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1972

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,167,934.4	1,106,318.5	1,137,415.2	976,854.5	1,012,573.2	1,270,241.6	782,419.7	703,615.0	636,256.6	633,469.7	573,014.2	867,477.0	10,867,589.5
Bridger													
Energy (MWh)	98,532.9	23,699.5	-	-	-	12,879.7	240,486.0	293,625.5	229,902.1	383,548.6	394,729.3	457,233.7	2,134,637.3
Cost ($ x 1000)	$ 2,308.6	$ 550.7	$ -	$ -	$ -	$ 302.8	$ 5,490.6	$ 6,640.7	$ 5,225.3	$ 8,545.1	$ 8,763.4	$ 10,091.7	$ 47,918.8
Boardman													
Energy (MWh)	24,668.8	21,274.2	8,238.0	9,046.3	-	-	31,241.3	36,286.7	36,358.0	34,927.3	34,844.5	37,484.9	274,369.9
Cost ($ x 1000)	$ 472.6	$ 408.4	$ 166.0	$ 176.1	$ -	$ -	$ 564.9	$ 650.5	$ 648.6	$ 629.7	$ 625.4	$ 668.9	$ 5,011.1
Valmy													
Energy (MWh)	-	-	-	-	-	-	14,068.8	-	-	10,079.0	-	64,283.8	88,431.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 509.1	$ -	$ -	$ 359.1	$ -	$ 2,209.1	$ 3,077.3
Danskin													
Energy (MWh)	-	-	-	-	-	0.1	433.4	39.1	0.0	426.7	21.4	-	920.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 15.0	$ 1.4	$ 0.0	$ 15.3	$ 0.8	$ -	$ 32.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 465.6	$ 452.2	$ 437.1	$ 466.5	$ 438.3	$ 451.5	$ 5,093.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	28.1	-	-	-	-	-	28.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ 1.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ 1.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	17,097.4	754.5	210.0	4,271.2	115,241.7	33,249.2	460,333.4	350,942.0	245,569.9	21,367.4	44,037.6	11,580.0	1,304,654.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	50,839.1	30,313.7	28,584.5	34,450.7	144,533.8	95,538.4	522,766.2	413,147.9	270,903.5	51,837.5	77,983.2	50,665.4	1,771,564.0
Market Cost ($ x 1000)	$ 455.5	$ 19.7	$ 4.9	$ 104.9	$ 2,506.2	$ 565.1	$ 12,092.5	$ 9,927.6	$ 7,316.2	$ 633.4	$ 1,304.9	$ 311.2	$ 35,242.0
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,298.3	$ 1,635.6	$ 1,147.2	$ 1,316.0	$ 3,684.1	$ 5,220.5	$ 17,074.0	$ 14,931.4	$ 8,702.7	$ 2,299.5	$ 3,530.1	$ 2,870.7	$ 64,710.1
Surplus Sales													
Energy (MWh)	93,697.3	128,721.7	145,915.4	94,131.3	24,644.1	131,753.5	-	1,490.9	16,257.6	123,295.9	38,432.0	216,348.2	1,014,687.7
Revenue Including Transmission Costs ($ x 1000)	$ 2,333.0	$ 2,746.2	$ 2,388.1	$ 1,581.1	$ 334.3	$ 1,000.7	$ -	$ 35.1	$ 404.3	$ 3,700.7	$ 1,194.3	$ 7,669.8	$ 23,387.7
Transmission Costs ($ x 1000)	$ 93.7	$ 128.7	$ 145.9	$ 94.1	$ 24.6	$ 131.8	$ -	$ 1.5	$ 16.3	$ 123.3	$ 38.4	$ 216.3	$ 1,014.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,239.3	$ 2,617.5	$ 2,242.2	$ 1,486.9	$ 309.7	$ 868.9	$ -	$ 33.6	$ 388.0	$ 3,577.4	$ 1,155.9	$ 7,453.5	$ 22,373.0
Net Power Supply Expenses ($ x 1000)	$ 3,186.0	$ 291.6	$ (529.8)	$ 441.5	$ 3,824.8	$ 5,091.0	$ 24,105.1	$ 22,641.2	$ 14,625.6	$ 8,722.6	$ 12,201.3	$ 8,838.4	$ 103,439.2

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1973

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	988,789.1	862,192.1	774,267.8	748,475.8	1,120,409.9	832,993.9	602,165.4	538,282.9	637,436.8	503,789.9	405,258.6	816,525.0	8,830,587.2
Bridger													
Energy (MWh)	432,781.2	422,603.9	390,263.7	314,687.0	233,031.2	184,164.5	424,438.4	454,277.6	409,543.1	436,919.8	427,948.3	472,679.5	4,603,338.1
Cost ($ x 1000)	$ 9,600.9	$ 9,308.1	$ 8,673.8	$ 7,013.7	$ 5,221.1	$ 4,156.1	$ 9,422.4	$ 10,032.3	$ 9,090.2	$ 9,669.2	$ 9,459.6	$ 10,401.7	$ 102,049.1
Boardman													
Energy (MWh)	31,007.3	34,528.7	37,955.8	15,813.7	-	21,254.8	39,583.7	38,824.6	36,733.1	36,309.3	32,058.5	33,289.4	357,358.9
Cost ($ x 1000)	$ 569.7	$ 614.4	$ 676.1	$ 288.1	$ -	$ 395.9	$ 701.0	$ 689.4	$ 654.3	$ 650.9	$ 582.7	$ 604.6	$ 6,427.1
Valmy													
Energy (MWh)	37,964.7	79,858.8	1,280.0	-	-	-	94,535.0	121,416.4	84,345.3	141,753.1	139,350.1	149,806.1	850,309.7
Cost ($ x 1000)	$ 1,306.9	$ 2,733.0	$ 45.8	$ -	$ -	$ -	$ 3,225.3	$ 4,126.0	$ 2,880.8	$ 4,791.6	$ 4,713.8	$ 5,055.5	$ 28,878.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,789.3	4,053.3	0.0	-	-	-	6,842.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 129.0	$ 192.4	$ 0.0	$ -	$ -	$ -	$ 321.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 579.7	$ 643.2	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,382.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	498.3	202.1	-	-	-	-	700.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.4	$ 9.7	$ -	$ -	$ -	$ -	$ 33.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.4	$ 9.7	$ -	$ -	$ -	$ -	$ 33.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	1,492.4	-	13,699.1	11,157.8	5,980.1	152,005.5	364,987.1	233,988.4	64,206.3	7,184.5	46,248.1	6,730.8	907,680.1
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	35,234.2	29,559.2	42,073.6	41,337.4	35,272.2	214,294.7	427,419.9	296,194.2	89,539.9	37,654.7	80,193.7	45,816.2	1,374,589.8
Market Cost ($ x 1000)	$ 37.7	$ -	$ 442.5	$ 333.1	$ 161.2	$ 4,121.7	$ 13,671.2	$ 9,239.5	$ 2,528.8	$ 237.7	$ 1,475.1	$ 176.4	$ 32,424.9
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,880.5	$ 1,615.9	$ 1,584.9	$ 1,544.2	$ 1,339.1	$ 8,777.2	$ 18,652.8	$ 14,243.2	$ 3,915.3	$ 1,903.8	$ 3,700.3	$ 2,735.9	$ 61,893.1
Surplus Sales													
Energy (MWh)	277,492.3	375,886.1	217,571.4	194,115.3	256,272.0	5,886.3	-	8,025.7	100,406.1	165,417.5	42,632.2	257,297.5	1,901,002.5
Revenue Including Transmission Costs ($ x 1000)	$ 9,407.9	$ 12,998.5	$ 6,680.1	$ 5,576.0	$ 6,653.3	$ 106.1	$ -	$ 226.8	$ 3,109.1	$ 6,347.8	$ 1,730.8	$ 11,144.5	$ 63,981.0
Transmission Costs ($ x 1000)	$ 277.5	$ 375.9	$ 217.6	$ 194.1	$ 256.3	$ 5.9	$ -	$ 8.0	$ 100.4	$ 165.4	$ 42.6	$ 257.3	$ 1,901.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,130.5	$ 12,622.6	$ 6,462.5	$ 5,381.9	$ 6,397.0	$ 100.2	$ -	$ 218.8	$ 3,008.7	$ 6,182.4	$ 1,688.1	$ 10,887.2	$ 62,080.0
Net Power Supply Expenses ($ x 1000)	$ 4,573.3	$ 1,963.3	$ 4,917.2	$ 3,900.4	$ 613.5	$ 13,665.5	$ 32,604.5	$ 29,525.1	$ 13,969.0	$ 11,284.3	$ 17,205.7	$ 8,362.0	$ 142,583.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1974

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,258,656.9	1,154,309.6	1,146,425.3	959,742.3	1,037,482.4	1,244,988.3	982,122.1	710,065.3	604,187.9	727,360.7	593,668.4	842,272.0	11,261,281.1
Bridger													
Energy (MWh)	32,171.0	-	13,852.4	15,840.9	-	-	196,523.1	287,432.4	139,771.4	380,661.0	407,251.1	463,149.5	1,936,652.8
Cost ($ x 1000)	$ 763.7	$ -	$ 337.0	$ 376.9	$ -	$ -	$ 4,527.1	$ 6,506.6	$ 3,186.4	$ 8,487.2	$ 9,029.5	$ 10,210.4	$ 43,424.8
Boardman													
Energy (MWh)	18,439.9	18,205.8	16,830.4	5,966.7	-	-	30,278.7	36,835.7	36,116.3	36,253.5	35,712.1	38,005.9	272,644.9
Cost ($ x 1000)	$ 357.8	$ 349.2	$ 331.3	$ 118.0	$ -	$ -	$ 549.9	$ 658.9	$ 644.9	$ 650.0	$ 638.7	$ 676.9	$ 4,975.5
Valmy													
Energy (MWh)	-	-	-	-	-	-	14,926.7	-	-	-	-	57,159.2	72,085.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 540.1	$ -	$ -	$ -	$ -	$ 1,966.2	$ 2,506.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	8.0	27.0	22.8	47.5	116.3	-	221.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.3	$ 0.9	$ 0.8	$ 1.7	$ 4.5	$ -	$ 8.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.9	$ 451.8	$ 437.9	$ 452.9	$ 442.0	$ 451.5	$ 5,069.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	4,297.1	938.4	326.6	7,389.1	92,168.4	38,819.9	307,757.0	349,960.1	357,490.2	15,114.5	28,067.9	9,584.6	1,211,913.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	38,038.8	30,497.7	28,701.1	37,568.6	121,460.5	101,109.2	370,189.8	412,165.9	382,823.8	45,584.7	62,013.5	48,669.9	1,678,823.5
Market Cost ($ x 1000)	$ 110.6	$ 22.2	$ 8.2	$ 177.9	$ 2,062.1	$ 695.3	$ 7,996.0	$ 9,967.4	$ 10,581.1	$ 455.1	$ 800.1	$ 259.2	$ 33,135.3
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,953.5	$ 1,638.1	$ 1,150.6	$ 1,389.0	$ 3,240.0	$ 5,350.8	$ 12,977.5	$ 14,971.1	$ 11,967.6	$ 2,121.2	$ 3,025.3	$ 2,818.7	$ 62,603.5
Surplus Sales													
Energy (MWh)	98,995.7	150,117.3	177,500.9	92,897.9	26,492.0	99,202.0	2,600.6	1,309.7	5,763.7	198,914.3	56,601.3	188,464.2	1,098,859.5
Revenue Including Transmission Costs ($ x 1000)	$ 1,806.9	$ 2,771.0	$ 3,101.6	$ 1,534.2	$ 364.0	$ 823.9	$ 56.5	$ 29.7	$ 138.9	$ 5,920.0	$ 1,737.9	$ 6,663.0	$ 24,947.7
Transmission Costs ($ x 1000)	$ 99.0	$ 150.1	$ 177.5	$ 92.9	$ 26.5	$ 99.2	$ 2.6	$ 1.3	$ 5.8	$ 198.9	$ 56.6	$ 188.5	$ 1,098.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,708.0	$ 2,620.9	$ 2,924.1	$ 1,441.3	$ 337.5	$ 724.7	$ 53.9	$ 28.4	$ 133.1	$ 5,721.1	$ 1,681.3	$ 6,474.5	$ 23,848.8
Net Power Supply Expenses ($ x 1000)	$ 1,712.9	$ (319.2)	$ (706.1)	$ 878.9	$ 3,352.8	$ 5,062.7	$ 18,991.6	$ 22,560.0	$ 16,103.7	$ 5,990.2	$ 11,454.2	$ 9,649.1	$ 94,730.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1975

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	976,387.9	1,101,679.9	1,192,408.0	1,134,802.9	1,094,780.9	1,262,788.4	890,024.7	727,197.5	842,459.8	739,719.1	614,719.1	981,403.2	11,558,371.5
Bridger													
Energy (MWh)	233,691.2	235,725.6	169,007.6	31,799.8	42,427.7	25,496.8	289,981.3	352,780.6	264,803.9	382,194.7	388,729.4	422,335.9	2,838,974.6
Cost ($ x 1000)	$ 5,321.9	$ 5,322.5	$ 3,950.2	$ 735.4	$ 984.3	$ 600.3	$ 6,545.5	$ 7,914.1	$ 5,944.2	$ 8,526.6	$ 8,657.7	$ 9,391.2	$ 63,893.9
Boardman													
Energy (MWh)	27,805.9	26,469.8	26,740.1	13,912.1	-	9,132.3	34,856.8	37,384.7	35,859.0	33,606.0	30,700.4	30,599.3	307,066.3
Cost ($ x 1000)	$ 520.6	$ 491.0	$ 504.3	$ 258.9	$ -	$ 174.8	$ 625.6	$ 667.3	$ 640.9	$ 609.5	$ 561.9	$ 563.4	$ 5,618.3
Valmy													
Energy (MWh)	-	-	-	-	-	-	4,328.9	-	-	24,707.9	40,291.5	111,335.2	180,663.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 156.6	$ -	$ -	$ 865.5	$ 1,399.7	$ 3,781.2	$ 6,203.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	1.3	21.0	0.3	4.7	-	-	27.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 0.8	$ 0.0	$ 0.2	$ -	$ -	$ 1.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 451.6	$ 437.1	$ 451.4	$ 437.5	$ 451.5	$ 5,062.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	74,384.9	396.0	-	-	37,943.3	27,104.8	310,341.4	269,254.5	89,856.4	12,145.2	31,365.6	11,145.4	863,937.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	108,126.6	29,955.3	28,374.5	30,179.5	67,235.4	89,394.0	372,774.2	331,460.4	115,189.9	42,615.4	65,311.2	50,230.8	1,330,847.2
Market Cost ($ x 1000)	$ 2,052.7	$ 12.8	$ -	$ -	$ 970.8	$ 545.2	$ 8,666.2	$ 8,308.6	$ 2,865.9	$ 368.9	$ 859.1	$ 281.5	$ 24,931.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,895.6	$ 1,628.7	$ 1,142.4	$ 1,211.1	$ 2,148.8	$ 5,200.6	$ 13,647.7	$ 13,312.3	$ 4,252.4	$ 2,035.0	$ 3,084.3	$ 2,841.0	$ 54,400.0
Surplus Sales													
Energy (MWh)	97,740.3	340,960.8	388,243.3	284,475.3	72,009.6	139,929.3	519.3	3,620.8	101,128.2	231,838.0	97,578.4	335,082.9	2,093,126.3
Revenue Including Transmission Costs ($ x 1000)	$ 2,899.3	$ 8,755.1	$ 8,787.4	$ 5,997.8	$ 1,468.5	$ 1,580.9	$ 14.1	$ 93.6	$ 2,566.1	$ 7,344.2	$ 3,302.0	$ 11,752.0	$ 54,561.0
Transmission Costs ($ x 1000)	$ 97.7	$ 341.0	$ 388.2	$ 284.5	$ 72.0	$ 139.9	$ 0.5	$ 3.6	$ 101.1	$ 231.8	$ 97.6	$ 335.1	$ 2,093.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,801.5	$ 8,414.1	$ 8,399.1	$ 5,713.4	$ 1,396.5	$ 1,441.0	$ 13.6	$ 90.0	$ 2,465.0	$ 7,112.3	$ 3,204.4	$ 11,416.9	$ 52,467.9
Net Power Supply Expenses ($ x 1000)	$ 7,282.4	$ (657.5)	$ (2,403.1)	$ (3,071.7)	$ 2,186.9	$ 4,971.3	$ 21,412.4	$ 22,255.4	$ 8,809.7	$ 5,375.6	$ 10,936.8	$ 5,611.5	$ 82,709.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1976

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,077,755.6	1,115,378.4	1,181,456.5	972,835.4	1,050,837.2	957,388.6	679,231.9	623,324.3	680,171.5	557,588.0	539,591.1	775,066.6	10,210,625.0
Bridger													
Energy (MWh)	231,977.3	172,314.2	125,864.3	58,194.4	62,796.1	-	319,667.6	352,552.5	272,589.1	410,144.1	443,812.4	480,281.7	2,930,193.7
Cost ($ x 1000)	$ 5,278.0	$ 3,919.5	$ 2,888.8	$ 1,368.1	$ 1,454.0	$ -	$ 7,195.4	$ 7,894.7	$ 6,137.4	$ 9,124.4	$ 9,792.8	$ 10,554.3	$ 65,607.3
Boardman													
Energy (MWh)	22,494.9	23,815.7	27,245.5	8,985.8	-	19,620.2	36,259.1	34,923.8	30,136.7	34,051.0	36,156.4	39,159.1	312,848.0
Cost ($ x 1000)	$ 426.3	$ 447.3	$ 512.1	$ 173.9	$ -	$ 367.8	$ 650.1	$ 629.7	$ 553.3	$ 616.3	$ 645.5	$ 694.5	$ 5,716.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	4,519.9	7,313.4	-	105,346.3	109,607.8	149,583.5	376,370.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 162.7	$ 253.0	$ -	$ 3,576.0	$ 3,749.9	$ 5,048.5	$ 12,790.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	184.4	42.9	-	17.7	-	-	245.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.3	$ 1.7	$ -	$ 0.7	$ -	$ -	$ 9.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 458.0	$ 452.6	$ 437.1	$ 451.9	$ 437.5	$ 451.5	$ 5,071.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	31,057.8	480.1	-	3,465.5	45,366.4	208,001.2	489,152.4	365,690.9	178,653.1	14,871.7	2,649.4	2,158.2	1,341,546.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	64,799.6	30,039.3	28,374.5	33,645.0	74,658.5	270,290.5	551,585.1	427,896.8	203,986.6	45,341.9	36,595.0	41,243.6	1,808,456.5
Market Cost ($ x 1000)	$ 780.8	$ 13.1	$ -	$ 89.6	$ 1,104.0	$ 4,552.9	$ 14,394.0	$ 11,254.7	$ 5,432.3	$ 417.9	$ 72.3	$ 62.5	$ 38,174.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,623.7	$ 1,629.0	$ 1,142.4	$ 1,300.7	$ 2,281.9	$ 9,208.3	$ 19,375.6	$ 16,258.4	$ 6,818.8	$ 2,084.0	$ 2,297.5	$ 2,622.0	$ 67,642.3
Surplus Sales													
Energy (MWh)	148,731.4	288,658.9	334,644.0	147,430.9	55,839.0	465.3	-	814.2	29,683.7	161,482.8	123,600.5	224,540.3	1,515,891.0
Revenue Including Transmission Costs ($ x 1000)	$ 4,104.0	$ 7,033.0	$ 7,620.1	$ 2,919.2	$ 1,110.9	$ 6.1	$ -	$ 19.2	$ 742.6	$ 5,473.1	$ 4,445.2	$ 9,061.0	$ 42,534.6
Transmission Costs ($ x 1000)	$ 148.7	$ 288.7	$ 334.6	$ 147.4	$ 55.8	$ 0.5	$ -	$ 0.8	$ 29.7	$ 161.5	$ 123.6	$ 224.5	$ 1,515.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,955.3	$ 6,744.4	$ 7,285.5	$ 2,771.8	$ 1,055.0	$ 5.6	$ -	$ 18.4	$ 712.9	$ 5,311.7	$ 4,321.6	$ 8,836.5	$ 41,018.7
Net Power Supply Expenses ($ x 1000)	$ 4,718.5	$ (434.2)	$ (2,343.1)	$ 507.2	$ 3,131.2	$ 10,007.1	$ 27,841.7	$ 25,470.0	$ 13,233.7	$ 10,540.9	$ 12,601.4	$ 10,534.4	$ 115,808.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1977

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	684,088.1	659,287.3	674,327.4	454,493.5	556,920.7	505,444.7	535,335.4	450,031.2	419,094.8	425,292.8	408,041.2	561,148.7	6,333,505.8
Bridger													
Energy (MWh)	483,431.4	436,524.0	476,444.3	391,668.0	305,298.4	283,598.2	478,695.0	477,153.4	434,607.1	463,109.2	458,419.7	483,033.5	5,171,982.4
Cost ($ x 1000)	$ 10,617.5	$ 9,587.5	$ 10,477.2	$ 8,657.7	$ 6,813.5	$ 6,355.9	$ 10,522.4	$ 10,491.5	$ 9,608.0	$ 10,209.6	$ 10,086.0	$ 10,609.5	$ 114,036.3
Boardman													
Energy (MWh)	38,270.8	35,335.8	38,594.4	17,017.7	-	22,570.8	39,538.6	38,688.7	36,310.3	37,274.9	36,047.2	35,107.2	374,756.5
Cost ($ x 1000)	$ 680.9	$ 626.8	$ 685.9	$ 306.5	$ -	$ 418.8	$ 700.3	$ 687.3	$ 647.8	$ 665.7	$ 643.8	$ 632.5	$ 6,696.3
Valmy													
Energy (MWh)	154,872.9	135,565.9	73,085.9	23,840.2	14,575.3	-	134,924.3	152,868.2	141,645.0	152,004.1	150,254.7	158,886.3	1,292,522.8
Cost ($ x 1000)	$ 5,216.5	$ 4,574.5	$ 2,498.2	$ 829.0	$ 505.3	$ -	$ 4,576.7	$ 5,152.8	$ 4,786.8	$ 5,125.1	$ 5,060.0	$ 5,343.9	$ 43,668.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	6,791.0	5,350.3	1,522.5	186.0	-	-	13,849.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 359.4	$ 290.2	$ 81.7	$ 10.2	$ -	$ -	$ 741.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 810.1	$ 741.0	$ 518.8	$ 461.4	$ 437.5	$ 451.5	$ 5,802.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	829.9	532.2	7.7	-	-	-	1,369.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 44.5	$ 29.3	$ 0.4	$ -	$ -	$ -	$ 74.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 44.5	$ 29.3	$ 0.4	$ -	$ -	$ -	$ 74.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	670.2	-	101.6	52,699.5	231,879.4	372,918.0	333,160.9	269,295.4	147,123.5	4,841.6	10,417.0	33,558.4	1,456,665.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	34,411.9	29,559.2	28,476.1	82,879.1	261,171.6	435,207.3	395,593.7	331,501.3	172,457.0	35,311.8	44,362.6	72,643.8	1,923,575.3
Market Cost ($ x 1000)	$ 21.2	$ -	$ 2.8	$ 1,764.8	$ 7,978.0	$ 11,333.2	$ 15,154.4	$ 12,679.2	$ 6,740.8	$ 221.5	$ 423.7	$ 1,278.5	$ 57,598.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,864.1	$ 1,615.9	$ 1,145.1	$ 2,976.0	$ 9,155.9	$ 15,988.7	$ 20,135.9	$ 17,682.9	$ 8,127.3	$ 1,887.6	$ 2,649.0	$ 3,838.0	$ 87,066.2
Surplus Sales													
Energy (MWh)	146,808.2	243,419.5	262,654.4	43,701.2	5,540.4	-	279.3	10,899.5	48,452.9	122,167.7	54,951.1	50,004.8	988,879.0
Revenue Including Transmission Costs ($ x 1000)	$ 5,991.0	$ 9,723.8	$ 9,031.2	$ 1,425.1	$ 135.7	$ -	$ 8.1	$ 323.8	$ 1,546.1	$ 4,893.2	$ 2,436.9	$ 2,578.9	$ 38,093.9
Transmission Costs ($ x 1000)	$ 146.8	$ 243.4	$ 262.7	$ 43.7	$ 5.5	$ -	$ 0.3	$ 10.9	$ 48.5	$ 122.2	$ 55.0	$ 50.0	$ 988.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,844.2	$ 9,480.4	$ 8,768.5	$ 1,381.4	$ 130.1	$ -	$ 7.9	$ 312.9	$ 1,497.6	$ 4,771.1	$ 2,382.0	$ 2,528.9	$ 37,105.1
Net Power Supply Expenses ($ x 1000)	$ 12,880.6	$ 7,238.8	$ 6,437.0	$ 11,824.0	$ 16,794.9	$ 23,200.0	$ 36,782.0	$ 34,471.8	$ 22,191.6	$ 13,578.3	$ 16,494.2	$ 18,346.4	$ 220,239.6

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1978

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	581,145.0	729,773.3	743,366.7	854,018.0	995,782.6	894,807.2	732,698.6	522,051.1	625,214.6	573,715.8	517,350.1	765,904.7	8,535,827.8
Bridger													
Energy (MWh)	429,413.0	377,385.5	329,648.2	152,983.6	142,472.3	147,693.3	392,473.1	424,272.1	388,701.5	429,927.6	424,641.8	476,489.8	4,116,101.8
Cost ($ x 1000)	$ 9,533.3	$ 8,400.5	$ 7,393.2	$ 3,463.3	$ 3,206.2	$ 3,378.9	$ 8,767.3	$ 9,430.1	$ 8,642.4	$ 9,543.6	$ 9,408.0	$ 10,478.2	$ 91,645.0
Boardman													
Energy (MWh)	29,744.7	27,740.6	32,231.1	12,840.6	-	20,556.2	38,132.2	37,070.2	36,094.9	34,309.3	31,628.1	35,083.6	335,431.4
Cost ($ x 1000)	$ 550.3	$ 510.5	$ 588.4	$ 242.5	$ -	$ 385.2	$ 678.8	$ 662.5	$ 644.5	$ 620.2	$ 576.1	$ 632.1	$ 6,091.2
Valmy													
Energy (MWh)	10,598.2	-	-	-	-	-	53,298.9	107,549.8	55,885.0	133,069.0	134,932.4	152,039.6	647,372.8
Cost ($ x 1000)	$ 366.2	$ -	$ -	$ -	$ -	$ -	$ 1,826.3	$ 3,658.0	$ 1,915.9	$ 4,512.9	$ 4,568.6	$ 5,126.5	$ 21,974.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	1.3	2,919.5	-	-	-	-	2,920.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 133.3	$ -	$ -	$ -	$ -	$ 133.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 584.1	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,194.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	3.1	-	-	-	-	3.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ 0.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ 0.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	165,338.5	12,876.0	36,637.0	19,548.2	46,860.7	141,499.9	312,510.6	292,226.4	87,082.6	4,319.8	15,882.6	7,624.3	1,142,406.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	199,080.2	42,435.2	65,011.5	49,727.7	76,152.8	203,789.1	374,943.3	354,432.3	112,416.2	34,790.0	49,828.2	46,709.7	1,609,316.2
Market Cost ($ x 1000)	$ 4,899.0	$ 325.6	$ 1,139.7	$ 555.0	$ 1,325.0	$ 3,429.0	$ 10,723.6	$ 10,561.1	$ 3,199.2	$ 115.8	$ 429.0	$ 205.7	$ 36,907.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 6,741.8	$ 1,941.5	$ 2,282.0	$ 1,766.1	$ 2,503.0	$ 8,084.4	$ 15,705.1	$ 15,564.9	$ 4,585.7	$ 1,781.9	$ 2,654.2	$ 2,765.2	$ 66,375.8
Surplus Sales													
Energy (MWh)	1,703.4	124,466.3	141,984.2	143,355.2	81,978.7	20,021.3	106.3	3,067.0	61,121.3	214,794.5	116,200.4	215,417.6	1,124,216.2
Revenue Including Transmission Costs ($ x 1000)	$ 57.8	$ 3,997.4	$ 4,129.8	$ 3,654.2	$ 2,216.4	$ 543.2	$ 3.2	$ 81.2	$ 1,793.4	$ 7,797.3	$ 4,478.0	$ 9,377.1	$ 38,129.1
Transmission Costs ($ x 1000)	$ 1.7	$ 124.5	$ 142.0	$ 143.4	$ 82.0	$ 20.0	$ 0.1	$ 3.1	$ 61.1	$ 214.8	$ 116.2	$ 215.4	$ 1,124.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 56.1	$ 3,873.0	$ 3,987.8	$ 3,510.8	$ 2,134.4	$ 523.2	$ 3.1	$ 78.1	$ 1,732.3	$ 7,582.5	$ 4,361.8	$ 9,161.7	$ 37,004.9
Net Power Supply Expenses ($ x 1000)	$ 17,481.4	$ 7,294.0	$ 6,674.9	$ 2,397.3	$ 4,025.1	$ 11,761.9	$ 27,425.1	$ 29,821.7	$ 14,493.4	$ 9,327.2	$ 13,282.6	$ 10,291.8	$ 154,276.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1979

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	906,942.9	843,579.7	1,001,330.9	913,806.7	957,177.9	808,231.9	587,058.8	498,572.7	443,999.5	499,765.3	413,386.2	528,576.3	8,402,428.6
Bridger													
Energy (MWh)	437,814.4	426,556.4	366,254.9	269,045.4	226,994.8	215,253.6	420,756.8	446,976.3	415,439.9	443,322.2	454,880.5	482,982.9	4,606,278.0
Cost ($ x 1000)	$ 9,677.9	$ 9,387.4	$ 8,145.2	$ 6,023.5	$ 5,092.6	$ 4,864.6	$ 9,348.5	$ 9,885.8	$ 9,208.6	$ 9,812.5	$ 10,014.9	$ 10,608.5	$ 102,070.0
Boardman													
Energy (MWh)	32,810.7	34,625.1	37,022.6	14,768.7	-	20,925.4	39,412.7	38,122.9	36,653.5	35,950.8	36,300.9	39,526.8	366,120.1
Cost ($ x 1000)	$ 597.3	$ 615.9	$ 661.8	$ 272.1	$ -	$ 390.6	$ 698.4	$ 678.7	$ 653.1	$ 645.4	$ 647.7	$ 700.2	$ 6,561.0
Valmy													
Energy (MWh)	70,363.5	80,044.3	1,533.1	-	-	-	101,972.7	124,130.2	86,550.8	142,266.0	146,959.0	165,808.8	919,628.5
Cost ($ x 1000)	$ 2,417.2	$ 2,743.6	$ 55.5	$ -	$ -	$ -	$ 3,479.7	$ 4,218.1	$ 2,954.7	$ 4,811.1	$ 4,955.4	$ 5,563.9	$ 31,199.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,432.4	4,362.4	583.2	-	-	-	7,377.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 113.5	$ 208.4	$ 27.6	$ -	$ -	$ -	$ 349.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 564.1	$ 659.2	$ 464.7	$ 451.2	$ 437.5	$ 451.5	$ 5,410.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	429.8	146.6	-	-	-	-	576.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.3	$ 7.1	$ -	$ -	$ -	$ -	$ 27.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.3	$ 7.1	$ -	$ -	$ -	$ -	$ 27.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	11,832.0	-	637.9	95.3	24,952.3	152,129.1	376,936.7	274,787.8	173,697.3	2,961.3	9,620.0	40,416.9	1,068,066.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	45,573.7	29,559.2	29,012.4	30,274.8	54,244.5	214,418.3	439,369.5	336,993.6	199,030.8	33,431.5	43,565.5	79,502.3	1,534,976.2
Market Cost ($ x 1000)	$ 379.5	$ -	$ 23.4	$ 2.9	$ 691.0	$ 4,149.5	$ 14,032.0	$ 10,853.7	$ 6,834.3	$ 85.3	$ 342.0	$ 1,866.4	$ 39,259.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,222.4	$ 1,615.9	$ 1,165.8	$ 1,214.0	$ 1,869.0	$ 8,805.0	$ 19,013.5	$ 15,857.4	$ 8,220.8	$ 1,751.4	$ 2,567.2	$ 4,425.8	$ 68,728.0
Surplus Sales													
Energy (MWh)	245,228.0	361,507.5	406,870.3	301,683.8	105,978.6	12,003.4	-	4,079.0	25,071.7	163,725.8	52,925.1	35,602.4	1,714,675.5
Revenue Including Transmission Costs ($ x 1000)	$ 8,649.3	$ 12,482.9	$ 11,641.3	$ 8,293.8	$ 2,916.6	$ 288.9	$ -	$ 113.0	$ 726.8	$ 6,304.2	$ 2,169.4	$ 1,630.4	$ 55,216.9
Transmission Costs ($ x 1000)	$ 245.2	$ 361.5	$ 406.9	$ 301.7	$ 106.0	$ 12.0	$ -	$ 4.1	$ 25.1	$ 163.7	$ 52.9	$ 35.6	$ 1,714.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,404.1	$ 12,121.4	$ 11,234.5	$ 7,992.2	$ 2,810.7	$ 276.9	$ -	$ 108.9	$ 701.7	$ 6,140.5	$ 2,116.5	$ 1,594.8	$ 53,502.2
Net Power Supply Expenses ($ x 1000)	$ 6,856.5	$ 2,555.9	$ (807.2)	$ (46.3)	$ 4,601.2	$ 14,219.8	$ 33,124.5	$ 31,197.3	$ 20,800.0	$ 11,331.0	$ 16,506.2	$ 20,155.1	$ 160,494.0

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1980

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	828,574.5	991,520.2	647,479.4	1,193,413.1	1,058,131.7	1,184,542.0	696,396.7	536,352.9	589,316.1	505,046.1	426,038.1	855,244.6	9,512,055.4
Bridger													
Energy (MWh)	386,027.1	378,782.2	276,900.7	114,829.4	51,318.5	-	362,918.2	409,309.6	360,469.7	421,468.2	447,236.5	479,971.7	3,689,231.8
Cost ($ x 1000)	$ 8,609.6	$ 8,428.6	$ 6,264.5	$ 2,664.6	$ 1,171.1	$ -	$ 8,122.5	$ 9,129.8	$ 8,031.5	$ 9,344.3	$ 9,861.5	$ 10,548.0	$ 82,176.0
Boardman													
Energy (MWh)	29,761.8	30,525.1	31,971.0	13,126.5	-	19,889.6	39,895.1	38,174.7	36,433.8	35,935.4	35,986.9	37,284.5	348,984.3
Cost ($ x 1000)	$ 550.6	$ 553.1	$ 584.4	$ 246.9	$ -	$ 371.9	$ 705.8	$ 679.4	$ 649.7	$ 645.2	$ 642.9	$ 665.8	$ 6,295.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	29,048.3	104,360.6	12,399.0	129,801.0	139,159.8	148,509.8	563,278.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,001.9	$ 3,554.5	$ 429.7	$ 4,400.0	$ 4,703.0	$ 5,014.4	$ 19,103.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,042.0	2,390.5	0.0	0.0	-	-	4,432.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 85.4	$ 102.6	$ 0.0	$ 0.0	$ -	$ -	$ 188.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 536.1	$ 553.4	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,249.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	380.6	42.7	-	-	-	-	423.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.1	$ 1.9	$ -	$ -	$ -	$ -	$ 18.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.1	$ 1.9	$ -	$ -	$ -	$ -	$ 18.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	62,605.2	-	106,287.1	-	40,401.2	49,153.0	398,326.4	294,337.8	150,829.7	13,838.4	20,270.8	815.7	1,136,865.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	96,346.9	29,559.2	134,661.6	30,179.5	69,693.3	111,442.2	460,759.2	356,543.7	176,163.2	44,308.6	54,216.3	39,901.1	1,603,775.1
Market Cost ($ x 1000)	$ 1,700.7	$ -	$ 3,132.7	$ -	$ 1,122.4	$ 1,242.2	$ 13,371.7	$ 10,112.8	$ 5,210.3	$ 450.4	$ 671.1	$ 21.8	$ 37,036.0
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,543.6	$ 1,615.9	$ 4,275.0	$ 1,211.1	$ 2,300.3	$ 5,897.7	$ 18,353.2	$ 15,116.5	$ 6,596.8	$ 2,116.5	$ 2,896.3	$ 2,581.3	$ 66,504.2
Surplus Sales													
Energy (MWh)	92,435.9	377,518.5	62,752.1	425,317.3	46,713.4	69,030.6	13.1	1,950.4	17,596.5	145,555.6	60,473.7	300,107.2	1,599,464.2
Revenue Including Transmission Costs ($ x 1000)	$ 2,988.9	$ 10,941.6	$ 1,779.8	$ 9,352.3	$ 1,091.1	$ 1,097.3	$ 0.3	$ 52.8	$ 473.4	$ 5,211.5	$ 2,313.4	$ 12,441.8	$ 47,744.3
Transmission Costs ($ x 1000)	$ 92.4	$ 377.5	$ 62.8	$ 425.3	$ 46.7	$ 69.0	$ 0.0	$ 2.0	$ 17.6	$ 145.6	$ 60.5	$ 300.1	$ 1,599.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,896.4	$ 10,564.1	$ 1,717.0	$ 8,927.0	$ 1,044.4	$ 1,028.3	$ 0.3	$ 50.8	$ 455.8	$ 5,065.9	$ 2,253.0	$ 12,141.7	$ 46,144.8
Net Power Supply Expenses ($ x 1000)	$ 10,153.2	$ 347.9	$ 9,806.0	$ (4,368.1)	$ 2,877.3	$ 5,677.9	$ 28,735.3	$ 28,984.7	$ 15,689.0	$ 11,891.2	$ 16,288.1	$ 7,119.4	$ 133,201.9

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1981

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	813,090.9	993,582.9	830,030.6	757,686.0	912,239.7	932,887.2	612,324.3	508,572.5	519,640.9	509,128.3	408,699.0	735,987.6	8,533,870.0
Bridger													
Energy (MWh)	407,004.5	364,791.5	289,299.5	222,715.6	131,943.6	88,178.4	392,957.9	442,656.9	392,831.2	440,095.6	452,187.6	482,946.2	4,107,608.5
Cost ($ x 1000)	$ 9,068.8	$ 8,133.0	$ 6,528.1	$ 5,044.8	$ 2,993.0	$ 2,004.6	$ 8,786.8	$ 9,799.1	$ 8,740.0	$ 9,747.7	$ 9,960.9	$ 10,607.7	$ 91,414.6
Boardman													
Energy (MWh)	29,115.4	27,461.8	28,826.1	13,668.0	-	22,154.3	37,722.3	38,663.5	36,085.5	35,841.0	35,604.6	39,217.1	344,359.6
Cost ($ x 1000)	$ 540.7	$ 506.2	$ 536.3	$ 255.2	$ -	$ 415.7	$ 672.5	$ 686.9	$ 644.4	$ 643.7	$ 637.0	$ 695.4	$ 6,234.1
Valmy													
Energy (MWh)	-	-	-	-	-	-	47,144.2	112,564.8	43,483.3	137,404.9	143,120.6	161,884.9	645,602.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,614.1	$ 3,825.8	$ 1,494.0	$ 4,650.7	$ 4,833.5	$ 5,439.1	$ 21,857.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	943.1	4,460.4	228.0	-	-	-	5,631.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 42.0	$ 203.6	$ 10.3	$ -	$ -	$ -	$ 255.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 492.6	$ 654.5	$ 447.4	$ 451.2	$ 437.5	$ 451.5	$ 5,317.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	110.8	-	-	-	-	110.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.1	$ -	$ -	$ -	$ -	$ 5.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.1	$ -	$ -	$ -	$ -	$ 5.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	52,105.5	1,536.2	27,720.0	27,024.2	108,224.3	160,632.6	437,918.6	279,159.5	157,550.5	4,349.8	19,268.6	1,879.0	1,277,368.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	85,847.2	31,095.4	56,094.5	57,203.7	137,516.4	222,921.8	500,351.3	341,365.4	182,884.1	34,820.0	53,214.2	40,964.4	1,744,278.5
Market Cost ($ x 1000)	$ 1,309.3	$ 44.8	$ 827.5	$ 754.7	$ 2,850.4	$ 3,875.8	$ 14,934.4	$ 10,554.7	$ 5,752.8	$ 117.8	$ 694.4	$ 57.5	$ 41,774.0
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,152.1	$ 1,660.7	$ 1,969.8	$ 1,965.8	$ 4,028.3	$ 8,531.3	$ 19,915.9	$ 15,558.4	$ 7,139.3	$ 1,783.9	$ 2,919.6	$ 2,617.0	$ 71,242.2
Surplus Sales													
Energy (MWh)	86,771.6	364,058.3	175,970.3	125,068.6	49,248.2	19,308.9	-	3,171.6	17,962.5	166,280.8	50,659.5	200,204.0	1,258,704.2
Revenue Including Transmission Costs ($ x 1000)	$ 2,828.6	$ 10,981.2	$ 4,939.9	$ 3,500.3	$ 1,122.7	$ 499.6	$ -	$ 85.4	$ 487.0	$ 6,184.6	$ 2,002.2	$ 9,098.7	$ 41,730.2
Transmission Costs ($ x 1000)	$ 86.8	$ 364.1	$ 176.0	$ 125.1	$ 49.2	$ 19.3	$ -	$ 3.2	$ 18.0	$ 166.3	$ 50.7	$ 200.2	$ 1,258.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,741.8	$ 10,617.2	$ 4,764.0	$ 3,375.2	$ 1,073.4	$ 480.3	$ -	$ 82.2	$ 469.0	$ 6,018.3	$ 1,951.5	$ 8,898.5	$ 40,471.5
Net Power Supply Expenses ($ x 1000)	$ 10,365.6	$ (2.8)	$ 4,669.3	$ 4,326.9	$ 6,398.3	$ 10,908.0	$ 31,482.0	$ 30,447.6	$ 17,996.1	$ 11,258.9	$ 16,836.9	$ 10,912.3	$ 155,599.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1982

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,009,681.2	1,029,566.7	1,143,961.1	968,733.9	1,114,970.9	1,266,950.2	1,018,148.7	743,421.7	947,226.1	789,422.2	694,032.4	1,053,853.9	11,779,969.0
Bridger													
Energy (MWh)	185,331.6	98,572.6	16,556.6	18,426.3	-	-	228,509.7	313,599.4	169,740.4	382,934.3	401,787.4	452,772.0	2,268,230.2
Cost ($ x 1000)	$ 4,332.3	$ 2,274.7	$ 391.3	$ 428.8	$ -	$ -	$ 5,209.6	$ 7,071.1	$ 3,861.7	$ 8,541.4	$ 8,934.6	$ 10,002.1	$ 51,047.6
Boardman													
Energy (MWh)	23,724.9	16,468.4	19,913.9	10,468.2	-	959.9	35,252.9	36,717.9	35,734.2	35,643.8	33,086.4	37,822.5	285,793.0
Cost ($ x 1000)	$ 455.1	$ 319.7	$ 384.4	$ 203.1	$ -	$ 18.3	$ 631.6	$ 657.1	$ 639.0	$ 640.7	$ 598.5	$ 674.1	$ 5,221.6
Valmy													
Energy (MWh)	-	-	-	-	-	-	5,186.7	-	-	-	-	65,147.3	70,334.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 187.7	$ -	$ -	$ -	$ -	$ 2,237.7	$ 2,425.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	3.7	4.1	3.8	29.1	2.0	21.3	63.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 0.1	$ 0.1	$ 1.1	$ 0.1	$ 1.0	$ 2.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.8	$ 451.0	$ 437.3	$ 452.2	$ 437.5	$ 452.5	$ 5,063.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	65,910.8	6,160.6	92.8	5,393.5	35,659.5	32,882.7	248,201.6	294,963.4	107,461.9	8,336.8	13,042.3	549.8	818,655.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	99,652.5	35,719.8	28,467.3	35,573.1	64,951.7	95,171.9	310,634.3	357,169.3	132,795.4	38,807.0	46,987.9	39,635.2	1,285,565.4
Market Cost ($ x 1000)	$ 1,661.8	$ 161.4	$ 2.1	$ 136.8	$ 790.0	$ 623.9	$ 6,826.8	$ 8,352.6	$ 3,327.8	$ 246.5	$ 345.6	$ 14.6	$ 22,489.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,504.6	$ 1,777.2	$ 1,144.5	$ 1,347.9	$ 1,967.9	$ 5,279.4	$ 11,808.3	$ 13,356.3	$ 4,714.3	$ 1,912.6	$ 2,570.8	$ 2,574.1	$ 51,958.0
Surplus Sales													
Energy (MWh)	70,112.4	127,436.9	180,595.8	106,996.0	47,453.6	116,184.7	6,294.7	5,687.7	128,320.4	255,831.7	133,727.3	388,451.8	1,567,093.1
Revenue Including Transmission Costs ($ x 1000)	$ 1,927.6	$ 2,755.4	$ 3,422.1	$ 2,062.4	$ 700.2	$ 1,054.0	$ 160.7	$ 144.0	$ 3,010.6	$ 7,692.1	$ 4,187.3	$ 13,531.9	$ 40,648.2
Transmission Costs ($ x 1000)	$ 70.1	$ 127.4	$ 180.6	$ 107.0	$ 47.5	$ 116.2	$ 6.3	$ 5.7	$ 128.3	$ 255.8	$ 133.7	$ 388.5	$ 1,567.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,857.5	$ 2,627.9	$ 3,241.5	$ 1,955.4	$ 652.7	$ 937.8	$ 154.4	$ 138.3	$ 2,882.3	$ 7,436.2	$ 4,053.5	$ 13,143.5	$ 39,081.1
Net Power Supply Expenses ($ x 1000)	$ 6,780.3	$ 2,058.2	$ (922.3)	$ 460.8	$ 1,765.5	$ 4,796.4	$ 18,133.7	$ 21,397.3	$ 6,770.0	$ 4,110.7	$ 8,487.8	$ 2,797.0	$ 76,635.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1983

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,225,696.0	1,108,021.6	1,188,719.2	1,118,173.8	1,254,274.5	1,243,068.3	938,643.1	771,170.5	952,737.7	928,722.1	651,427.4	1,115,641.1	12,496,295.3
Bridger													
Energy (MWh)	100,890.2	82,344.6	53,054.6	-	14,289.5	-	288,959.1	325,163.4	222,422.4	375,660.6	417,375.1	459,341.4	2,339,501.0
Cost ($ x 1000)	$ 2,338.4	$ 1,899.8	$ 1,241.9	$ -	$ 331.1	$ -	$ 6,544.6	$ 7,314.3	$ 5,037.1	$ 8,385.6	$ 9,262.2	$ 10,134.0	$ 52,488.8
Boardman													
Energy (MWh)	21,074.5	18,084.4	23,001.7	9,661.5	-	7,466.1	37,812.4	36,874.3	35,954.2	34,421.2	34,127.5	38,323.0	296,800.8
Cost ($ x 1000)	$ 404.9	$ 347.3	$ 437.9	$ 187.3	$ -	$ 141.4	$ 673.9	$ 659.5	$ 642.4	$ 622.0	$ 614.4	$ 681.7	$ 5,412.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	10,153.3	-	-	4,680.7	22,098.5	99,745.6	136,678.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 367.1	$ -	$ -	$ 167.8	$ 763.5	$ 3,420.6	$ 4,719.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	6.0	61.7	-	0.6	-	-	68.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.2	$ 2.3	$ -	$ 0.0	$ -	$ -	$ 2.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.9	$ 453.2	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,063.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	5,561.3	767.0	-	-	8,189.1	38,457.5	258,561.4	256,342.8	71,200.8	2,190.5	7,799.5	213.6	649,283.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	39,303.1	30,326.2	28,374.5	30,179.5	37,481.3	100,746.8	320,994.2	318,548.7	96,534.3	32,660.7	41,745.1	39,299.0	1,116,193.3
Market Cost ($ x 1000)	$ 158.3	$ 20.8	$ -	$ -	$ 199.6	$ 897.5	$ 7,416.9	$ 7,447.4	$ 2,189.3	$ 64.1	$ 214.3	$ 5.5	$ 18,613.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,001.1	$ 1,636.7	$ 1,142.4	$ 1,211.1	$ 1,377.6	$ 5,553.0	$ 12,398.4	$ 12,451.2	$ 3,575.8	$ 1,730.2	$ 2,439.5	$ 2,565.0	$ 48,081.8
Surplus Sales													
Energy (MWh)	138,665.1	185,882.6	264,850.7	231,783.5	173,592.3	104,417.9	5,133.7	6,587.7	150,460.0	385,132.1	124,605.6	491,547.7	2,262,658.8
Revenue Including Transmission Costs ($ x 1000)	$ 3,249.6	$ 4,000.1	$ 5,444.3	$ 4,394.0	$ 2,985.6	$ 1,230.3	$ 148.2	$ 171.9	$ 3,610.5	$ 11,481.1	$ 4,040.5	$ 17,464.9	$ 58,220.9
Transmission Costs ($ x 1000)	$ 138.7	$ 185.9	$ 264.9	$ 231.8	$ 173.6	$ 104.4	$ 5.1	$ 6.6	$ 150.5	$ 385.1	$ 124.6	$ 491.5	$ 2,262.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,110.9	$ 3,814.2	$ 5,179.4	$ 4,162.2	$ 2,812.0	$ 1,125.9	$ 143.1	$ 165.3	$ 3,460.0	$ 11,095.9	$ 3,915.9	$ 16,973.3	$ 55,958.3
Net Power Supply Expenses ($ x 1000)	$ 1,979.3	$ 384.0	$ (1,958.2)	$ (2,327.5)	$ (653.1)	$ 5,005.1	$ 20,291.8	$ 20,712.8	$ 6,232.3	$ 260.8	$ 9,601.1	$ 279.5	$ 59,808.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1984

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,221,129.1	1,110,986.9	1,207,086.4	1,101,581.8	1,235,789.9	1,230,597.8	1,081,020.8	791,162.3	948,732.9	789,953.6	699,572.3	1,002,888.3	12,420,502.0
Bridger													
Energy (MWh)	255,268.2	233,139.9	23,860.9	33,224.7	10,531.2	28,281.5	272,516.7	344,833.4	274,088.0	396,205.0	411,811.8	474,261.4	2,758,022.9
Cost ($ x 1000)	$ 5,781.7	$ 5,276.8	$ 550.2	$ 774.4	$ 255.6	$ 658.9	$ 6,158.0	$ 7,736.1	$ 6,182.2	$ 8,822.5	$ 9,135.8	$ 10,433.4	$ 61,765.7
Boardman													
Energy (MWh)	27,410.5	25,380.9	28,143.6	13,032.5	-	15,721.3	35,713.8	36,489.6	33,710.4	35,375.7	33,271.8	38,675.8	322,925.9
Cost ($ x 1000)	$ 514.6	$ 474.3	$ 525.8	$ 245.5	$ -	$ 297.9	$ 639.0	$ 653.6	$ 608.0	$ 636.6	$ 601.3	$ 687.1	$ 5,883.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	4,328.9	-	-	67,180.2	61,940.2	139,519.4	272,968.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 156.6	$ -	$ -	$ 2,283.9	$ 2,137.7	$ 4,718.5	$ 9,296.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	0.2	0.4	-	0.2	-	-	0.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 0.0	$ -	$ 0.0	$ -	$ -	$ 0.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.9	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	3,211.6	138.5	-	-	10,616.6	28,693.9	157,622.4	220,605.3	60,038.3	3,644.5	6,628.1	194.5	491,393.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	36,953.3	29,697.8	28,374.5	30,179.5	39,908.8	90,983.1	220,055.2	282,811.2	85,371.9	34,114.7	40,573.7	39,279.9	958,303.5
Market Cost ($ x 1000)	$ 98.8	$ 3.9	$ -	$ -	$ 265.5	$ 697.2	$ 4,442.6	$ 6,622.1	$ 1,877.0	$ 111.3	$ 177.8	$ 5.0	$ 14,301.2
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,941.6	$ 1,619.8	$ 1,142.4	$ 1,211.1	$ 1,443.5	$ 5,352.7	$ 9,424.1	$ 11,625.8	$ 3,263.5	$ 1,777.4	$ 2,403.0	$ 2,564.5	$ 43,769.4
Surplus Sales													
Energy (MWh)	292,476.8	346,326.4	259,173.1	251,795.9	153,774.6	118,723.6	22,180.8	10,062.0	184,700.6	331,819.4	204,997.6	433,823.1	2,609,853.9
Revenue Including Transmission Costs ($ x 1000)	$ 7,894.0	$ 8,704.6	$ 5,803.9	$ 5,306.8	$ 2,731.6	$ 1,631.5	$ 599.9	$ 276.4	$ 4,542.2	$ 10,835.5	$ 7,044.5	$ 16,354.8	$ 71,725.7
Transmission Costs ($ x 1000)	$ 292.5	$ 346.3	$ 259.2	$ 251.8	$ 153.8	$ 118.7	$ 22.2	$ 10.1	$ 184.7	$ 331.8	$ 205.0	$ 433.8	$ 2,609.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,601.5	$ 8,358.3	$ 5,544.7	$ 5,055.0	$ 2,577.8	$ 1,512.8	$ 577.7	$ 266.4	$ 4,357.5	$ 10,503.6	$ 6,839.5	$ 15,920.9	$ 69,115.8
Net Power Supply Expenses ($ x 1000)	$ 982.3	$ (672.9)	$ (2,927.3)	$ (2,387.7)	$ (428.4)	$ 5,233.3	$ 16,250.7	$ 20,200.1	$ 6,133.3	$ 3,467.9	$ 7,875.6	$ 2,934.1	$ 56,661.0

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1985

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,078,395.9	1,119,881.8	954,444.2	1,221,389.9	1,151,048.8	796,516.3	602,118.3	536,509.4	617,249.5	524,208.4	410,574.9	750,331.8	9,762,669.3
Bridger													
Energy (MWh)	358,733.3	345,465.4	296,594.1	42,501.0	34,161.8	71,529.0	357,922.5	406,904.2	372,484.0	438,862.3	447,092.9	479,115.4	3,651,365.9
Cost ($ x 1000)	$ 8,009.6	$ 7,713.2	$ 6,674.5	$ 968.6	$ 777.9	$ 1,635.7	$ 8,024.6	$ 9,081.5	$ 8,302.2	$ 9,722.9	$ 9,858.6	$ 10,530.9	$ 81,300.1
Boardman													
Energy (MWh)	28,906.5	27,381.5	37,193.9	13,581.2	-	21,746.3	39,146.8	37,463.9	36,570.1	36,501.2	35,303.3	37,003.1	350,797.8
Cost ($ x 1000)	$ 537.5	$ 505.0	$ 664.4	$ 253.9	$ -	$ 403.4	$ 694.3	$ 668.6	$ 651.8	$ 653.8	$ 632.4	$ 661.5	$ 6,326.6
Valmy													
Energy (MWh)	-	-	-	-	-	-	18,083.5	101,499.9	14,805.4	126,685.5	139,122.6	149,404.9	549,601.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 627.5	$ 3,458.4	$ 512.1	$ 4,292.7	$ 4,701.8	$ 5,042.8	$ 18,635.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,873.8	1,885.4	-	93.8	-	-	4,853.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 120.3	$ 80.9	$ -	$ 4.1	$ -	$ -	$ 205.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 570.9	$ 531.8	$ 437.1	$ 455.3	$ 437.5	$ 451.5	$ 5,266.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	144.7	7.7	-	-	-	-	152.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.1	$ 0.3	$ -	$ -	$ -	$ -	$ 6.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.1	$ 0.3	$ -	$ -	$ -	$ -	$ 6.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	15,120.7	-	6,032.2	-	20,060.1	302,478.5	508,706.7	301,021.7	119,973.7	3,255.3	23,755.8	6,716.2	1,307,120.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	48,862.4	29,559.2	34,406.7	30,179.5	49,352.2	364,767.7	571,139.4	363,227.6	145,307.2	33,725.5	57,701.4	45,801.6	1,774,030.5
Market Cost ($ x 1000)	$ 424.5	$ -	$ 188.5	$ -	$ 552.2	$ 7,903.7	$ 16,938.1	$ 10,238.1	$ 4,243.7	$ 92.0	$ 783.9	$ 198.4	$ 41,563.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,267.4	$ 1,615.9	$ 1,330.8	$ 1,211.1	$ 1,730.2	$ 12,559.1	$ 21,919.6	$ 15,241.9	$ 5,630.2	$ 1,758.1	$ 3,009.1	$ 2,757.9	$ 71,031.3
Surplus Sales													
Energy (MWh)	266,612.3	469,413.2	294,369.0	381,424.4	102,129.0	7,746.0	-	2,271.2	29,232.3	169,074.1	47,631.9	200,854.1	1,970,757.4
Revenue Including Transmission Costs ($ x 1000)	$ 7,949.0	$ 13,162.0	$ 7,994.3	$ 8,576.3	$ 2,314.5	$ 185.6	$ -	$ 60.8	$ 803.7	$ 6,073.8	$ 1,834.2	$ 8,320.7	$ 57,275.0
Transmission Costs ($ x 1000)	$ 266.6	$ 469.4	$ 294.4	$ 381.4	$ 102.1	$ 7.7	$ -	$ 2.3	$ 29.2	$ 169.1	$ 47.6	$ 200.9	$ 1,970.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,682.4	$ 12,692.5	$ 7,699.9	$ 8,194.9	$ 2,212.4	$ 177.9	$ -	$ 58.6	$ 774.5	$ 5,904.7	$ 1,786.6	$ 8,119.8	$ 55,304.3
Net Power Supply Expenses ($ x 1000)	$ 3,477.8	$ (2,544.1)	$ 1,368.9	$ (5,325.0)	$ 746.0	$ 14,856.9	$ 31,843.1	$ 28,923.9	$ 14,758.9	$ 10,978.1	$ 16,852.8	$ 11,324.8	$ 127,262.0

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1986

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	986,310.2	1,082,860.1	1,198,784.2	1,174,993.2	1,201,320.7	1,249,509.7	977,878.8	661,785.8	622,756.8	681,677.9	600,074.4	865,249.8	11,303,201.6
Bridger													
Energy (MWh)	291,312.0	137,792.2	42,304.7	27,327.1	-	15,404.4	309,195.5	379,330.3	325,151.1	394,731.4	432,984.2	477,392.9	2,832,925.9
Cost ($ x 1000)	$ 6,572.5	$ 3,134.4	$ 992.9	$ 637.0	$ -	$ 353.4	$ 6,970.4	$ 8,490.0	$ 7,259.9	$ 8,778.2	$ 9,560.7	$ 10,496.3	$ 63,245.7
Boardman													
Energy (MWh)	27,584.2	21,325.0	26,855.5	13,392.6	-	9,171.2	38,941.4	37,966.1	36,355.6	35,120.6	35,841.7	38,432.4	320,986.4
Cost ($ x 1000)	$ 517.2	$ 406.1	$ 506.1	$ 251.0	$ -	$ 178.6	$ 691.2	$ 676.3	$ 648.5	$ 632.7	$ 640.7	$ 683.4	$ 5,831.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	4,478.7	11,342.7	-	100,428.8	95,370.1	145,844.5	357,464.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 161.4	$ 390.6	$ -	$ 3,414.8	$ 3,279.4	$ 4,929.7	$ 12,175.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	175.1	695.7	0.0	50.8	-	-	921.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.8	$ 27.8	$ 0.0	$ 2.1	$ -	$ -	$ 36.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 457.5	$ 478.7	$ 437.1	$ 453.2	$ 437.5	$ 451.5	$ 5,098.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	7.4	-	-	-	-	-	7.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.3	$ -	$ -	$ -	$ -	$ -	$ 0.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.3	$ -	$ -	$ -	$ -	$ -	$ 0.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	51,769.9	906.3	-	-	10,779.0	32,596.6	205,631.4	293,437.6	168,993.6	11,022.2	5,761.4	1,417.4	782,315.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	85,511.7	30,465.6	28,374.5	30,179.5	40,071.2	94,885.9	268,064.1	355,643.5	194,327.1	41,492.4	39,706.9	40,502.8	1,249,225.2
Market Cost ($ x 1000)	$ 1,414.6	$ 26.5	$ -	$ -	$ 286.9	$ 703.8	$ 6,244.5	$ 9,463.5	$ 5,608.0	$ 358.2	$ 174.9	$ 38.3	$ 24,319.3
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,257.5	$ 1,642.4	$ 1,142.4	$ 1,211.1	$ 1,464.9	$ 5,359.3	$ 11,226.0	$ 14,467.2	$ 6,994.5	$ 2,024.3	$ 2,400.1	$ 2,597.8	$ 53,787.5
Surplus Sales													
Energy (MWh)	142,438.0	219,555.7	268,020.2	319,667.7	108,943.7	122,092.0	7,303.3	1,542.1	21,416.3	262,496.4	161,813.6	306,624.0	1,941,912.9
Revenue Including Transmission Costs ($ x 1000)	$ 4,173.8	$ 5,326.0	$ 5,872.9	$ 6,783.5	$ 2,112.6	$ 1,474.3	$ 200.2	$ 38.5	$ 584.2	$ 8,719.9	$ 5,750.5	$ 12,060.8	$ 53,097.3
Transmission Costs ($ x 1000)	$ 142.4	$ 219.6	$ 268.0	$ 319.7	$ 108.9	$ 122.1	$ 7.3	$ 1.5	$ 21.4	$ 262.5	$ 161.8	$ 306.6	$ 1,941.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 4,031.3	$ 5,106.5	$ 5,604.9	$ 6,463.8	$ 2,003.7	$ 1,352.3	$ 192.9	$ 37.0	$ 562.7	$ 8,457.4	$ 5,588.7	$ 11,754.2	$ 51,155.4
Net Power Supply Expenses ($ x 1000)	$ 6,661.7	$ 390.9	$ (2,564.4)	$ (3,928.5)	$ (88.5)	$ 4,975.6	$ 19,313.8	$ 24,465.8	$ 14,777.4	$ 6,845.8	$ 10,729.7	$ 7,404.6	$ 88,983.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1987

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	894,808.0	751,298.1	838,694.6	839,704.8	683,952.2	582,139.2	581,020.4	489,931.0	443,983.6	469,270.9	416,775.7	497,629.7	7,489,207.9
Bridger													
Energy (MWh)	461,521.9	432,851.7	438,792.0	323,835.9	287,697.7	258,286.6	449,956.0	467,454.7	414,863.9	435,179.2	449,259.1	479,651.1	4,899,349.9
Cost ($ x 1000)	$ 10,177.7	$ 9,513.8	$ 9,692.0	$ 7,230.2	$ 6,439.4	$ 5,800.8	$ 9,945.6	$ 10,296.8	$ 9,197.0	$ 9,649.0	$ 9,902.1	$ 10,541.6	$ 108,386.1
Boardman													
Energy (MWh)	33,158.6	34,435.8	38,244.7	15,060.5	-	21,270.8	39,344.7	38,752.0	35,545.2	34,181.7	33,208.4	33,692.3	356,894.6
Cost ($ x 1000)	$ 602.6	$ 613.0	$ 680.5	$ 276.5	$ -	$ 396.1	$ 697.4	$ 688.3	$ 636.1	$ 618.3	$ 600.3	$ 610.8	$ 6,419.9
Valmy													
Energy (MWh)	99,651.2	106,531.6	5,609.9	-	-	-	113,861.5	135,283.1	103,563.1	140,021.5	142,692.7	153,570.2	1,000,784.8
Cost ($ x 1000)	$ 3,415.5	$ 3,639.1	$ 200.9	$ -	$ -	$ -	$ 3,878.1	$ 4,584.0	$ 3,534.9	$ 4,741.0	$ 4,820.0	$ 5,175.1	$ 33,988.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,614.1	5,870.5	617.0	-	-	-	9,101.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 127.4	$ 293.5	$ 30.5	$ -	$ -	$ -	$ 451.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 578.0	$ 744.3	$ 467.6	$ 451.2	$ 437.5	$ 451.5	$ 5,512.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	285.8	489.9	-	-	-	-	775.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 14.1	$ 24.8	$ -	$ -	$ -	$ -	$ 38.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 14.1	$ 24.8	$ -	$ -	$ -	$ -	$ 38.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	1,099.1	-	3,954.7	936.2	152,020.6	322,837.2	342,030.2	251,492.6	160,305.3	8,475.0	17,764.2	73,239.3	1,334,154.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	34,840.8	29,559.2	32,329.2	31,115.8	181,312.7	385,126.4	404,463.0	313,698.5	185,638.8	38,945.2	51,709.8	112,324.7	1,801,064.1
Market Cost ($ x 1000)	$ 30.7	$ -	$ 142.6	$ 27.4	$ 4,757.5	$ 8,964.0	$ 13,637.1	$ 10,808.1	$ 6,477.9	$ 246.5	$ 572.5	$ 2,999.1	$ 48,663.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,873.6	$ 1,615.9	$ 1,285.0	$ 1,238.5	$ 5,935.5	$ 13,619.5	$ 18,618.7	$ 15,811.8	$ 7,864.4	$ 1,912.6	$ 2,797.7	$ 5,558.5	$ 78,131.6
Surplus Sales													
Energy (MWh)	275,702.4	301,820.7	325,395.5	283,501.9	20,535.5	-	112.9	6,257.2	27,017.6	126,577.1	51,470.3	16,053.1	1,434,444.2
Revenue Including Transmission Costs ($ x 1000)	$ 10,087.3	$ 11,025.9	$ 10,148.1	$ 8,065.5	$ 466.4	$ -	$ 3.0	$ 183.9	$ 805.2	$ 4,885.4	$ 2,181.3	$ 743.5	$ 48,595.5
Transmission Costs ($ x 1000)	$ 275.7	$ 301.8	$ 325.4	$ 283.5	$ 20.5	$ -	$ 0.1	$ 6.3	$ 27.0	$ 126.6	$ 51.5	$ 16.1	$ 1,434.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,811.6	$ 10,724.0	$ 9,822.7	$ 7,782.0	$ 445.8	$ -	$ 2.9	$ 177.6	$ 778.2	$ 4,758.8	$ 2,129.9	$ 727.4	$ 47,161.1
Net Power Supply Expenses ($ x 1000)	$ 6,603.6	$ 4,972.2	$ 2,434.8	$ 1,399.5	$ 12,379.3	$ 20,253.0	$ 33,728.9	$ 31,972.5	$ 20,922.0	$ 12,613.2	$ 16,427.7	$ 21,610.1	$ 185,316.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1988

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,211.3	538,881.5	684,701.4	578,132.2	653,834.5	591,015.2	529,990.5	444,477.7	433,196.1	412,502.4	408,854.0	487,140.7	6,282,937.4
Bridger													
Energy (MWh)	465,476.4	436,263.3	470,704.4	373,970.5	300,194.7	278,191.3	473,106.5	476,186.2	434,805.5	457,068.9	441,223.0	481,942.2	5,089,132.8
Cost ($ x 1000)	$ 10,257.1	$ 9,582.3	$ 10,362.0	$ 8,302.5	$ 6,711.1	$ 6,236.3	$ 10,410.3	$ 10,472.1	$ 9,612.0	$ 10,088.4	$ 9,740.8	$ 10,587.6	$ 112,362.4
Boardman													
Energy (MWh)	31,626.2	34,577.7	38,024.5	16,142.4	-	21,647.7	39,417.8	38,773.7	36,491.9	36,408.4	32,479.7	34,365.0	359,954.9
Cost ($ x 1000)	$ 579.2	$ 615.2	$ 677.1	$ 293.1	$ -	$ 401.9	$ 698.5	$ 688.6	$ 650.6	$ 652.4	$ 589.2	$ 621.1	$ 6,466.8
Valmy													
Energy (MWh)	140,602.7	135,975.0	53,602.7	6,367.0	-	-	134,266.1	151,841.1	141,948.2	149,694.8	142,771.4	157,394.6	1,214,463.5
Cost ($ x 1000)	$ 4,753.7	$ 4,587.5	$ 1,839.7	$ 222.2	$ -	$ -	$ 4,555.8	$ 5,120.2	$ 4,796.5	$ 5,051.9	$ 4,822.4	$ 5,296.5	$ 41,046.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	6,751.2	6,702.9	1,128.9	96.6	-	-	14,679.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 351.7	$ 357.4	$ 59.6	$ 5.2	$ -	$ -	$ 773.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 802.3	$ 808.3	$ 496.7	$ 456.4	$ 437.5	$ 451.5	$ 5,835.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	910.2	696.8	-	-	-	-	1,607.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 48.0	$ 37.7	$ -	$ -	$ -	$ -	$ 85.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 48.0	$ 37.7	$ -	$ -	$ -	$ -	$ 85.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	70,589.0	292.3	215.5	20,658.0	163,949.7	293,679.3	344,576.0	275,044.2	138,207.9	7,172.3	26,616.3	71,051.8	1,412,052.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	104,330.8	29,851.5	28,590.0	50,837.5	193,241.9	355,968.5	407,008.8	337,250.0	163,541.4	37,642.5	60,561.8	110,137.1	1,878,962.0
Market Cost ($ x 1000)	$ 2,242.1	$ 8.3	$ 5.9	$ 609.7	$ 5,467.4	$ 8,804.1	$ 15,281.9	$ 12,776.9	$ 6,263.4	$ 320.2	$ 824.4	$ 3,189.0	$ 55,793.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,084.9	$ 1,624.2	$ 1,148.2	$ 1,820.8	$ 6,645.3	$ 13,459.5	$ 20,263.4	$ 17,780.7	$ 7,649.9	$ 1,986.3	$ 3,049.6	$ 5,748.4	$ 85,261.2
Surplus Sales													
Energy (MWh)	13,965.0	122,694.7	247,346.1	99,246.3	14,838.8	-	21.7	10,705.7	53,922.8	102,399.4	43,707.4	10,164.8	719,012.8
Revenue Including Transmission Costs ($ x 1000)	$ 536.9	$ 4,773.4	$ 8,260.8	$ 3,207.1	$ 333.0	$ -	$ 0.7	$ 325.6	$ 1,723.1	$ 4,035.6	$ 1,910.8	$ 485.7	$ 25,592.5
Transmission Costs ($ x 1000)	$ 14.0	$ 122.7	$ 247.3	$ 99.2	$ 14.8	$ -	$ 0.0	$ 10.7	$ 53.9	$ 102.4	$ 43.7	$ 10.2	$ 719.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 522.9	$ 4,650.7	$ 8,013.4	$ 3,107.8	$ 318.2	$ -	$ 0.7	$ 314.9	$ 1,669.2	$ 3,933.2	$ 1,867.1	$ 475.5	$ 24,873.5
Net Power Supply Expenses ($ x 1000)	$ 19,497.7	$ 12,072.8	$ 6,412.8	$ 7,967.0	$ 13,488.6	$ 20,534.3	$ 36,777.5	$ 34,592.6	$ 21,536.5	$ 14,302.1	$ 16,772.4	$ 22,229.7	$ 226,184.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1989

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,412.6	582,298.2	928,497.6	923,812.5	936,751.2	774,604.2	576,045.1	497,429.2	453,303.3	511,897.1	412,006.7	692,924.5	7,809,982.3
Bridger													
Energy (MWh)	480,091.2	435,431.4	394,369.3	311,008.9	241,004.3	246,970.7	449,492.7	465,885.0	422,945.1	452,956.6	460,331.0	483,274.3	4,843,760.4
Cost ($ x 1000)	$ 10,550.4	$ 9,565.6	$ 8,741.4	$ 6,949.7	$ 5,402.3	$ 5,556.2	$ 9,925.2	$ 10,265.3	$ 9,359.2	$ 10,005.8	$ 10,124.3	$ 10,614.3	$ 107,059.9
Boardman													
Energy (MWh)	35,895.1	34,546.5	34,714.2	14,200.4	-	22,314.1	39,543.6	38,446.7	36,491.3	36,721.6	36,810.7	39,481.5	369,165.7
Cost ($ x 1000)	$ 644.5	$ 614.7	$ 626.4	$ 263.3	$ -	$ 415.1	$ 700.4	$ 683.6	$ 650.6	$ 657.2	$ 655.5	$ 699.5	$ 6,610.9
Valmy													
Energy (MWh)	117,623.1	116,349.7	811.7	-	-	-	114,950.5	145,010.7	117,582.2	147,449.9	151,252.8	165,968.2	1,076,998.7
Cost ($ x 1000)	$ 4,015.8	$ 3,958.2	$ 29.4	$ -	$ -	$ -	$ 3,916.7	$ 4,899.8	$ 4,004.4	$ 4,980.5	$ 5,091.8	$ 5,568.9	$ 36,465.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,721.0	4,993.4	423.3	-	-	-	9,137.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 182.4	$ 251.1	$ 21.1	$ -	$ -	$ -	$ 454.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 633.0	$ 702.0	$ 458.2	$ 451.2	$ 437.5	$ 451.5	$ 5,515.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	343.1	266.3	-	-	-	-	609.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.1	$ 13.6	$ -	$ -	$ -	$ -	$ 30.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.1	$ 13.6	$ -	$ -	$ -	$ -	$ 30.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	74,620.2	67.5	3,074.4	419.5	35,447.9	152,015.8	344,946.7	242,253.6	142,265.0	771.0	7,538.2	1,727.6	1,005,147.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	108,362.0	29,626.7	31,448.9	30,599.0	64,740.0	214,305.0	407,379.5	304,459.5	167,598.5	31,241.2	41,483.8	40,813.0	1,472,057.1
Market Cost ($ x 1000)	$ 2,644.0	$ 1.9	$ 115.4	$ 13.4	$ 917.0	$ 4,257.0	$ 13,930.9	$ 10,336.2	$ 5,927.2	$ 24.9	$ 329.0	$ 62.8	$ 38,559.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,486.9	$ 1,617.8	$ 1,257.8	$ 1,224.5	$ 2,094.9	$ 8,912.5	$ 18,912.4	$ 15,339.9	$ 7,313.7	$ 1,691.0	$ 2,554.2	$ 2,622.3	$ 68,027.9
Surplus Sales													
Energy (MWh)	14,119.0	145,400.9	361,552.9	353,399.8	110,040.1	11,362.3	44.2	11,264.1	41,155.4	189,254.3	59,718.8	161,665.0	1,458,976.9
Revenue Including Transmission Costs ($ x 1000)	$ 563.7	$ 5,445.1	$ 10,426.6	$ 9,721.3	$ 2,923.1	$ 299.8	$ 1.2	$ 334.8	$ 1,258.0	$ 7,535.6	$ 2,525.3	$ 8,029.7	$ 49,064.3
Transmission Costs ($ x 1000)	$ 14.1	$ 145.4	$ 361.6	$ 353.4	$ 110.0	$ 11.4	$ 0.0	$ 11.3	$ 41.2	$ 189.3	$ 59.7	$ 161.7	$ 1,459.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 549.5	$ 5,299.7	$ 10,065.0	$ 9,367.9	$ 2,813.1	$ 288.4	$ 1.2	$ 323.5	$ 1,216.9	$ 7,346.3	$ 2,465.6	$ 7,868.0	$ 47,605.3
Net Power Supply Expenses ($ x 1000)	$ 19,493.9	$ 10,770.9	$ 989.1	$ (494.1)	$ 5,134.5	$ 15,032.0	$ 34,103.6	$ 31,580.6	$ 20,569.3	$ 10,439.4	$ 16,397.7	$ 12,088.5	$ 176,105.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1990

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	647,633.0	721,444.1	699,682.2	665,804.6	658,879.5	728,196.0	548,118.6	464,526.4	443,970.1	456,161.5	414,584.4	483,020.9	6,932,021.2
Bridger													
Energy (MWh)	446,359.0	368,955.9	345,984.9	308,445.4	228,987.2	226,169.6	443,765.4	462,788.2	412,000.4	448,843.5	444,175.9	482,522.4	4,618,997.6
Cost ($ x 1000)	$ 9,873.4	$ 8,231.3	$ 7,726.0	$ 6,900.1	$ 5,150.1	$ 5,100.3	$ 9,809.1	$ 10,203.2	$ 9,124.8	$ 9,923.3	$ 9,800.1	$ 10,599.2	$ 102,440.8
Boardman													
Energy (MWh)	31,053.1	26,226.8	30,290.0	14,393.1	-	23,436.8	39,487.1	38,464.6	36,436.5	36,043.9	32,931.8	36,389.2	345,152.9
Cost ($ x 1000)	$ 570.4	$ 487.3	$ 558.7	$ 266.3	$ -	$ 435.4	$ 699.5	$ 683.9	$ 649.8	$ 646.8	$ 596.1	$ 652.1	$ 6,246.2
Valmy													
Energy (MWh)	94,039.6	44,593.8	8,206.8	-	-	-	113,517.9	127,895.3	100,924.7	145,684.3	142,437.6	159,686.5	936,986.4
Cost ($ x 1000)	$ 3,224.1	$ 1,533.8	$ 296.9	$ -	$ -	$ -	$ 3,866.0	$ 4,344.9	$ 3,441.6	$ 4,924.4	$ 4,811.9	$ 5,369.3	$ 31,812.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	5,927.3	5,096.8	711.6	25.5	-	-	11,761.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 284.0	$ 250.2	$ 34.6	$ 1.3	$ -	$ -	$ 570.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 734.7	$ 701.0	$ 471.7	$ 452.4	$ 437.5	$ 451.5	$ 5,631.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	670.5	417.2	-	-	-	-	1,087.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 32.5	$ 20.8	$ -	$ -	$ -	$ -	$ 53.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 32.5	$ 20.8	$ -	$ -	$ -	$ -	$ 53.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	46,212.6	13,568.6	45,660.1	21,198.8	226,113.0	208,509.0	377,569.0	288,615.2	168,648.5	3,431.7	23,228.9	71,282.9	1,494,038.4
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	79,954.4	43,127.8	74,034.6	51,378.3	255,405.2	270,798.3	440,001.8	350,821.0	193,982.1	33,901.9	57,174.5	110,368.2	1,960,948.1
Market Cost ($ x 1000)	$ 1,274.4	$ 335.4	$ 1,387.1	$ 593.8	$ 6,206.2	$ 5,700.6	$ 14,918.7	$ 11,986.0	$ 6,743.6	$ 121.9	$ 728.8	$ 3,205.8	$ 53,202.3
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,117.3	$ 1,951.3	$ 2,529.4	$ 1,804.9	$ 7,384.1	$ 10,356.1	$ 19,900.2	$ 16,989.8	$ 8,130.1	$ 1,788.0	$ 2,954.0	$ 5,765.3	$ 82,670.5
Surplus Sales													
Energy (MWh)	50,761.7	151,475.8	129,913.5	113,814.2	10,814.4	1,772.8	60.4	4,785.8	30,837.1	129,648.1	49,127.4	11,183.6	684,194.9
Revenue Including Transmission Costs ($ x 1000)	$ 1,955.8	$ 5,339.8	$ 3,873.8	$ 3,379.4	$ 169.6	$ 42.9	$ 1.6	$ 135.7	$ 923.2	$ 4,950.0	$ 2,038.5	$ 494.5	$ 23,304.8
Transmission Costs ($ x 1000)	$ 50.8	$ 151.5	$ 129.9	$ 113.8	$ 10.8	$ 1.8	$ 0.1	$ 4.8	$ 30.8	$ 129.6	$ 49.1	$ 11.2	$ 684.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,905.0	$ 5,188.3	$ 3,743.9	$ 3,265.6	$ 158.7	$ 41.1	$ 1.5	$ 130.9	$ 892.4	$ 4,820.4	$ 1,989.4	$ 483.3	$ 22,620.6
Net Power Supply Expenses ($ x 1000)	$ 15,225.8	$ 7,330.0	$ 7,766.3	$ 6,141.9	$ 12,825.8	$ 16,287.2	$ 35,040.5	$ 32,812.5	$ 20,925.6	$ 12,914.6	$ 16,610.1	$ 22,354.2	$ 206,234.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1991

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,263.9	582,265.4	659,443.2	472,287.6	722,939.0	751,310.5	564,710.2	471,755.7	444,049.5	434,662.6	412,721.1	489,663.4	6,526,072.3
Bridger													
Energy (MWh)	407,666.7	352,877.2	354,307.2	250,280.7	243,237.3	261,996.3	438,339.5	468,399.9	430,032.8	455,067.0	453,751.4	482,762.4	4,598,718.4
Cost ($ x 1000)	$ 9,082.1	$ 7,879.1	$ 7,922.6	$ 5,628.2	$ 5,457.0	$ 5,886.7	$ 9,700.2	$ 10,315.8	$ 9,516.2	$ 10,048.2	$ 9,992.3	$ 10,604.1	$ 102,032.2
Boardman													
Energy (MWh)	23,274.6	25,907.4	28,454.0	8,751.4	-	24,271.6	39,021.0	38,266.4	36,798.1	36,799.7	35,000.3	38,634.1	335,178.5
Cost ($ x 1000)	$ 440.3	$ 482.4	$ 530.6	$ 169.8	$ -	$ 448.2	$ 692.4	$ 680.9	$ 655.3	$ 658.4	$ 627.8	$ 686.5	$ 6,072.5
Valmy													
Energy (MWh)	78,291.9	72,143.1	811.7	-	-	-	122,089.2	144,558.4	119,048.2	148,409.4	146,312.3	165,390.0	997,054.1
Cost ($ x 1000)	$ 2,696.9	$ 2,462.3	$ 29.4	$ -	$ -	$ -	$ 4,142.7	$ 4,884.2	$ 4,054.0	$ 5,011.0	$ 4,934.9	$ 5,550.6	$ 33,766.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,956.1	5,280.9	665.1	6.9	-	-	8,909.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 146.6	$ 268.8	$ 33.5	$ 0.4	$ -	$ -	$ 449.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 597.3	$ 719.6	$ 470.6	$ 451.5	$ 437.5	$ 451.5	$ 5,510.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	38.1	295.8	-	-	-	-	333.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.9	$ 15.3	$ -	$ -	$ -	$ -	$ 17.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.9	$ 15.3	$ -	$ -	$ -	$ -	$ 17.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	187,621.6	63,050.5	54,794.3	177,118.6	160,156.4	153,100.9	361,903.1	263,934.8	141,622.5	4,964.9	11,617.9	59,278.0	1,639,163.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	221,363.4	92,609.7	83,168.7	207,298.2	189,448.5	215,390.2	424,335.9	326,140.7	166,956.1	35,435.1	45,563.5	98,363.3	2,106,073.2
Market Cost ($ x 1000)	$ 4,905.2	$ 1,506.8	$ 1,464.6	$ 4,778.3	$ 4,631.2	$ 4,517.8	$ 14,398.0	$ 11,406.7	$ 6,063.6	$ 198.1	$ 411.5	$ 2,851.6	$ 57,133.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 6,748.0	$ 3,122.7	$ 2,607.0	$ 5,989.5	$ 5,809.2	$ 9,173.3	$ 19,379.5	$ 16,410.4	$ 7,450.1	$ 1,864.2	$ 2,636.7	$ 5,411.1	$ 86,601.7
Surplus Sales													
Energy (MWh)	2,554.3	72,917.1	97,888.5	12,390.7	23,169.0	6,148.0	52.9	9,470.5	40,362.0	119,369.8	51,176.5	14,014.3	449,513.6
Revenue Including Transmission Costs ($ x 1000)	$ 96.8	$ 2,545.1	$ 2,949.8	$ 327.5	$ 432.8	$ 153.7	$ 1.4	$ 278.8	$ 1,235.3	$ 4,617.5	$ 2,201.3	$ 650.5	$ 15,490.7
Transmission Costs ($ x 1000)	$ 2.6	$ 72.9	$ 97.9	$ 12.4	$ 23.2	$ 6.1	$ 0.1	$ 9.5	$ 40.4	$ 119.4	$ 51.2	$ 14.0	$ 449.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 94.2	$ 2,472.2	$ 2,851.9	$ 315.2	$ 409.7	$ 147.5	$ 1.4	$ 269.3	$ 1,195.0	$ 4,498.1	$ 2,150.2	$ 636.5	$ 15,041.2
Net Power Supply Expenses ($ x 1000)	$ 19,218.9	$ 11,788.8	$ 8,636.6	$ 11,908.6	$ 11,306.8	$ 15,797.2	$ 34,512.6	$ 32,756.8	$ 20,951.3	$ 13,535.2	$ 16,479.0	$ 22,067.3	$ 218,959.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1992

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,358.7	456,227.2	609,111.9	456,823.6	503,043.2	414,594.5	506,323.7	404,210.7	381,501.6	368,163.8	413,248.9	446,596.4	5,480,204.3
Bridger													
Energy (MWh)	475,748.6	435,836.1	476,249.8	360,401.8	298,847.3	280,178.9	475,251.8	474,345.6	428,234.6	442,537.6	451,707.2	482,011.2	5,081,350.6
Cost ($ x 1000)	$ 10,463.3	$ 9,573.7	$ 10,473.3	$ 8,030.2	$ 6,673.0	$ 6,276.2	$ 10,453.3	$ 10,435.1	$ 9,480.1	$ 9,796.7	$ 9,951.2	$ 10,589.0	$ 112,195.2
Boardman													
Energy (MWh)	34,084.2	34,588.5	38,500.9	14,916.5	-	21,782.8	39,406.4	38,917.7	35,864.3	34,547.0	33,740.5	34,404.6	360,753.5
Cost ($ x 1000)	$ 616.8	$ 615.3	$ 684.4	$ 274.3	$ -	$ 403.9	$ 698.3	$ 690.8	$ 641.0	$ 623.9	$ 608.5	$ 621.7	$ 6,479.0
Valmy													
Energy (MWh)	147,333.4	136,315.4	60,921.5	5,121.5	3,613.6	-	133,760.8	152,724.4	140,750.5	145,053.5	145,178.4	156,966.0	1,227,739.2
Cost ($ x 1000)	$ 4,973.7	$ 4,598.3	$ 2,085.5	$ 179.2	$ 125.4	$ -	$ 4,537.4	$ 5,148.2	$ 4,758.3	$ 4,904.4	$ 4,898.9	$ 5,282.9	$ 41,492.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	9,404.8	9,488.1	3,745.2	-	-	-	22,638.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 488.7	$ 505.9	$ 197.6	$ -	$ -	$ -	$ 1,192.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 939.4	$ 956.8	$ 634.7	$ 451.2	$ 437.5	$ 451.5	$ 6,253.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	715.3	1,041.1	241.9	-	-	-	1,998.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 37.7	$ 56.3	$ 12.9	$ -	$ -	$ -	$ 106.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 37.7	$ 56.3	$ 12.9	$ -	$ -	$ -	$ 106.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	49,588.5	8,915.1	1,106.9	86,083.4	298,561.3	467,973.4	364,155.1	309,302.3	173,279.6	27,530.1	15,990.8	106,227.5	1,908,714.1
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	83,330.2	38,474.4	29,481.4	116,263.0	327,853.4	530,262.6	426,587.9	371,508.2	198,613.2	58,000.3	49,936.4	145,312.9	2,375,623.8
Market Cost ($ x 1000)	$ 1,673.8	$ 363.4	$ 30.0	$ 2,597.1	$ 9,906.3	$ 14,059.5	$ 16,277.9	$ 14,444.9	$ 7,722.1	$ 1,101.4	$ 542.7	$ 5,007.9	$ 73,727.0
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,516.7	$ 1,979.3	$ 1,172.4	$ 3,808.2	$ 11,084.2	$ 18,714.9	$ 21,259.4	$ 19,448.6	$ 9,108.6	$ 2,767.5	$ 2,767.9	$ 7,567.4	$ 103,195.2
Surplus Sales													
Energy (MWh)	12,580.7	48,589.8	185,992.4	27,319.4	928.9	-	24.2	7,015.2	31,757.2	57,279.0	51,631.7	4,476.8	427,595.4
Revenue Including Transmission Costs ($ x 1000)	$ 492.6	$ 1,870.9	$ 6,308.3	$ 868.4	$ 21.9	$ -	$ 0.7	$ 214.2	$ 978.2	$ 2,203.2	$ 2,244.0	$ 197.0	$ 15,399.2
Transmission Costs ($ x 1000)	$ 12.6	$ 48.6	$ 186.0	$ 27.3	$ 0.9	$ -	$ 0.0	$ 7.0	$ 31.8	$ 57.3	$ 51.6	$ 4.5	$ 427.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 480.0	$ 1,822.3	$ 6,122.3	$ 841.1	$ 21.0	$ -	$ 0.7	$ 207.2	$ 946.4	$ 2,145.9	$ 2,192.3	$ 192.5	$ 14,971.6
Net Power Supply Expenses ($ x 1000)	$ 19,436.2	$ 15,258.9	$ 8,692.5	$ 11,887.1	$ 18,311.9	$ 25,831.7	$ 37,924.8	$ 36,528.7	$ 23,689.3	$ 16,397.8	$ 16,471.6	$ 24,320.0	$ 254,750.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1993

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,439.9	565,154.9	988,242.6	972,486.9	1,141,588.6	1,175,650.8	699,849.9	608,533.6	560,202.4	531,182.4	410,080.0	688,383.0	8,861,795.0
Bridger													
Energy (MWh)	482,815.5	433,165.7	379,077.3	320,349.5	192,655.6	175,525.3	412,374.5	454,565.7	404,761.8	441,289.6	455,168.7	483,102.0	4,634,851.0
Cost ($ x 1000)	$ 10,605.1	$ 9,520.1	$ 8,430.8	$ 7,137.5	$ 4,325.9	$ 3,976.2	$ 9,183.0	$ 10,038.1	$ 8,979.5	$ 9,771.7	$ 10,020.7	$ 10,610.9	$ 102,599.5
Boardman													
Energy (MWh)	36,904.0	33,157.8	37,599.2	16,128.8	-	20,652.3	38,250.0	38,465.4	36,725.8	36,047.5	35,668.1	38,035.0	367,634.0
Cost ($ x 1000)	$ 660.0	$ 593.4	$ 670.6	$ 292.9	$ -	$ 386.6	$ 680.6	$ 683.9	$ 654.2	$ 646.9	$ 638.0	$ 677.3	$ 6,584.4
Valmy													
Energy (MWh)	104,013.4	87,975.2	1,082.2	-	-	-	91,162.6	121,547.0	87,390.9	143,009.7	145,593.0	161,384.1	943,158.2
Cost ($ x 1000)	$ 3,558.9	$ 3,017.3	$ 39.2	$ -	$ -	$ -	$ 3,113.6	$ 4,131.3	$ 2,987.5	$ 4,836.3	$ 4,912.1	$ 5,423.2	$ 32,019.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	71.8	1,614.2	-	-	-	-	1,686.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.3	$ 76.9	$ -	$ -	$ -	$ -	$ 80.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 454.0	$ 527.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,141.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	79,434.6	4,062.9	1,884.0	106.8	12,879.8	6,202.0	287,359.2	171,362.9	103,246.5	2,247.2	13,437.8	3,873.5	686,097.1
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	113,176.3	33,622.2	30,258.5	30,286.3	42,171.9	68,491.2	349,791.9	233,568.7	128,580.0	32,717.4	47,383.4	42,958.9	1,153,006.8
Market Cost ($ x 1000)	$ 2,737.8	$ 131.7	$ 64.7	$ 3.2	$ 383.0	$ 144.0	$ 10,342.2	$ 6,872.7	$ 3,986.8	$ 61.7	$ 504.5	$ 127.3	$ 25,359.6
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,580.7	$ 1,747.6	$ 1,207.1	$ 1,214.3	$ 1,561.0	$ 4,799.5	$ 15,323.7	$ 11,876.5	$ 5,373.3	$ 1,727.8	$ 2,729.7	$ 2,686.8	$ 54,827.8
Surplus Sales													
Energy (MWh)	9,087.6	100,223.5	407,978.6	413,040.6	243,966.9	193,470.7	59.8	13,066.7	60,470.3	193,237.0	51,726.4	153,063.0	1,839,391.0
Revenue Including Transmission Costs ($ x 1000)	$ 357.8	$ 3,607.3	$ 11,740.9	$ 11,230.1	$ 6,055.2	$ 4,484.9	$ 1.7	$ 389.4	$ 1,847.4	$ 7,506.8	$ 2,136.4	$ 7,152.2	$ 56,510.0
Transmission Costs ($ x 1000)	$ 9.1	$ 100.2	$ 408.0	$ 413.0	$ 244.0	$ 193.5	$ 0.1	$ 13.1	$ 60.5	$ 193.2	$ 51.7	$ 153.1	$ 1,839.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 348.7	$ 3,507.1	$ 11,332.9	$ 10,817.1	$ 5,811.2	$ 4,291.5	$ 1.6	$ 376.4	$ 1,787.0	$ 7,313.5	$ 2,084.7	$ 6,999.1	$ 54,670.6
Net Power Supply Expenses ($ x 1000)	$ 19,401.8	$ 11,685.8	$ (586.2)	$ (1,736.1)	$ 526.0	$ 5,307.5	$ 28,753.4	$ 26,881.2	$ 16,644.7	$ 10,120.3	$ 16,653.2	$ 12,850.6	$ 146,502.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1994

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	717,591.9	649,969.5	684,973.7	546,533.4	713,971.7	570,707.6	585,579.7	489,031.7	437,632.8	450,608.0	412,592.1	501,191.2	6,760,383.4
Bridger													
Energy (MWh)	483,442.6	436,402.7	478,923.4	382,623.3	302,073.5	283,201.5	475,196.4	473,502.1	433,374.0	461,104.1	459,017.8	483,402.4	5,152,263.8
Cost ($ x 1000)	$ 10,617.7	$ 9,585.1	$ 10,527.0	$ 8,476.2	$ 6,748.8	$ 6,347.9	$ 10,452.2	$ 10,418.2	$ 9,583.3	$ 10,169.4	$ 10,098.0	$ 10,616.9	$ 113,640.6
Boardman													
Energy (MWh)	39,510.5	34,650.2	39,169.4	16,541.2	-	21,701.5	39,013.3	37,960.3	36,567.8	37,234.8	36,774.7	39,999.6	379,123.3
Cost ($ x 1000)	$ 699.9	$ 616.3	$ 694.7	$ 299.2	$ -	$ 402.7	$ 692.3	$ 676.2	$ 651.8	$ 665.1	$ 654.9	$ 707.4	$ 6,760.4
Valmy													
Energy (MWh)	157,997.3	136,612.2	83,548.2	25,200.4	11,601.2	923.8	134,056.4	150,178.6	142,198.9	151,919.4	152,248.5	168,868.5	1,315,353.4
Cost ($ x 1000)	$ 5,315.7	$ 4,607.7	$ 2,853.6	$ 874.7	$ 404.4	$ 33.3	$ 4,548.7	$ 5,067.3	$ 4,804.4	$ 5,122.4	$ 5,123.4	$ 5,661.2	$ 44,416.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,394.6	4,347.5	738.8	210.3	-	-	7,691.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 127.0	$ 236.7	$ 39.8	$ 11.6	$ -	$ -	$ 415.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 577.7	$ 687.5	$ 476.9	$ 462.8	$ 437.5	$ 451.5	$ 5,476.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	194.2	214.3	-	-	-	-	408.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.4	$ 11.8	$ -	$ -	$ -	$ -	$ 22.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.4	$ 11.8	$ -	$ -	$ -	$ -	$ 22.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	167.6	-	-	19,194.7	106,322.1	308,356.9	293,855.9	239,339.4	135,677.4	2,867.4	7,461.1	50,657.0	1,163,899.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	33,909.3	29,559.2	28,374.5	49,374.2	135,614.2	370,646.2	356,288.6	301,545.2	161,011.0	33,337.6	41,406.6	89,742.4	1,630,809.2
Market Cost ($ x 1000)	$ 5.2	$ -	$ -	$ 568.8	$ 3,564.3	$ 9,404.6	$ 13,175.1	$ 11,107.2	$ 6,187.5	$ 121.1	$ 328.3	$ 2,683.1	$ 47,145.2
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,848.1	$ 1,615.9	$ 1,142.4	$ 1,779.9	$ 4,742.2	$ 14,060.1	$ 18,156.6	$ 16,110.9	$ 7,574.0	$ 1,787.2	$ 2,553.5	$ 5,242.5	$ 76,613.3
Surplus Sales													
Energy (MWh)	184,190.4	234,340.9	286,715.0	94,071.4	30,828.4	357.9	1,287.2	11,549.2	54,330.7	143,400.9	59,868.2	22,409.5	1,123,349.7
Revenue Including Transmission Costs ($ x 1000)	$ 7,722.0	$ 9,394.4	$ 9,863.2	$ 3,136.1	$ 753.3	$ 9.9	$ 37.3	$ 351.2	$ 1,775.4	$ 5,840.0	$ 2,677.1	$ 1,150.8	$ 42,710.6
Transmission Costs ($ x 1000)	$ 184.2	$ 234.3	$ 286.7	$ 94.1	$ 30.8	$ 0.4	$ 1.3	$ 11.5	$ 54.3	$ 143.4	$ 59.9	$ 22.4	$ 1,123.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,537.8	$ 9,160.1	$ 9,576.5	$ 3,042.0	$ 722.5	$ 9.5	$ 36.0	$ 339.6	$ 1,721.1	$ 5,696.6	$ 2,617.3	$ 1,128.4	$ 41,587.3
Net Power Supply Expenses ($ x 1000)	$ 11,289.4	$ 7,579.3	$ 6,040.2	$ 8,824.3	$ 11,623.3	$ 21,271.1	$ 34,401.8	$ 32,632.2	$ 21,369.3	$ 12,510.3	$ 16,250.0	$ 21,551.2	$ 205,342.6

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1995

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	604,382.8	810,913.6	779,482.9	840,815.1	1,227,646.0	1,273,870.9	814,113.2	577,051.9	618,729.7	517,561.3	453,142.9	903,500.5	9,421,211.0
Bridger													
Energy (MWh)	358,450.8	279,399.9	200,180.2	98,942.8	14,275.9	-	331,185.7	405,994.6	357,402.9	417,684.8	447,349.5	480,834.6	3,391,701.8
Cost ($ x 1000)	$ 8,014.4	$ 6,279.0	$ 4,605.4	$ 2,289.5	$ 330.8	$ -	$ 7,446.2	$ 9,063.3	$ 7,970.0	$ 9,268.4	$ 9,863.8	$ 10,565.4	$ 75,696.0
Boardman													
Energy (MWh)	28,287.9	24,120.0	26,815.0	13,142.3	-	9,545.0	39,147.0	38,289.9	36,918.1	35,803.8	36,147.1	38,831.1	327,047.1
Cost ($ x 1000)	$ 528.0	$ 455.0	$ 505.5	$ 247.1	$ -	$ 185.6	$ 694.3	$ 681.2	$ 657.1	$ 643.1	$ 645.3	$ 689.5	$ 5,931.9
Valmy													
Energy (MWh)	-	-	-	-	-	-	4,794.8	80,158.5	-	124,159.9	140,809.0	148,346.6	498,268.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 171.4	$ 2,750.6	$ -	$ 4,212.4	$ 4,760.1	$ 5,009.2	$ 16,903.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	24.5	1,783.7	12.4	0.0	0.0	-	1,820.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.0	$ 74.6	$ 0.5	$ 0.0	$ 0.0	$ -	$ 76.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 451.7	$ 525.4	$ 437.6	$ 451.2	$ 437.5	$ 451.5	$ 5,137.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	11.9	-	-	-	-	11.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ -	$ -	$ -	$ -	$ 0.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ -	$ -	$ -	$ -	$ 0.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	228,291.5	34,233.6	69,970.5	38,293.9	7,848.7	30,473.5	339,944.3	282,273.3	142,486.6	14,081.2	11,681.6	959.4	1,200,538.1
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	262,033.2	63,792.9	98,345.0	68,473.5	37,140.8	92,762.8	402,377.0	344,479.2	167,820.1	44,551.4	45,627.2	40,044.8	1,667,447.8
Market Cost ($ x 1000)	$ 6,533.6	$ 917.5	$ 1,903.4	$ 1,051.5	$ 210.6	$ 678.8	$ 10,819.2	$ 9,485.1	$ 5,006.6	$ 433.7	$ 377.8	$ 25.8	$ 37,443.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 8,376.4	$ 2,533.3	$ 3,045.7	$ 2,262.7	$ 1,388.6	$ 5,334.3	$ 15,800.8	$ 14,488.8	$ 6,393.1	$ 2,099.8	$ 2,603.1	$ 2,585.3	$ 66,911.9
Surplus Sales													
Energy (MWh)	4,882.5	125,355.0	76,552.6	95,178.0	146,609.6	129,291.4	207.6	2,546.5	23,704.4	148,758.8	80,911.9	350,757.6	1,184,755.9
Revenue Including Transmission Costs ($ x 1000)	$ 149.7	$ 3,686.7	$ 2,117.6	$ 2,391.8	$ 2,862.6	$ 1,484.9	$ 6.3	$ 68.6	$ 647.6	$ 5,224.5	$ 2,974.9	$ 14,240.3	$ 35,855.4
Transmission Costs ($ x 1000)	$ 4.9	$ 125.4	$ 76.6	$ 95.2	$ 146.6	$ 129.3	$ 0.2	$ 2.5	$ 23.7	$ 148.8	$ 80.9	$ 350.8	$ 1,184.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 144.8	$ 3,561.3	$ 2,041.0	$ 2,296.6	$ 2,716.0	$ 1,355.6	$ 6.1	$ 66.0	$ 623.9	$ 5,075.7	$ 2,894.0	$ 13,889.6	$ 34,670.6
Net Power Supply Expenses ($ x 1000)	$ 17,119.8	$ 6,020.5	$ 6,514.6	$ 2,939.0	$ (546.3)	$ 4,600.8	$ 24,558.3	$ 27,443.8	$ 14,833.9	$ 11,599.2	$ 15,415.7	$ 5,411.2	$ 135,910.7

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1996

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,116,245.0	1,098,326.8	1,176,928.7	994,448.3	1,099,455.3	1,321,670.0	766,070.5	665,518.0	669,787.6	509,956.7	456,375.3	1,030,118.2	10,904,900.5
Bridger													
Energy (MWh)	155,455.3	81,954.5	17,310.9	15,139.8	-	-	224,871.0	309,332.5	207,218.3	400,952.5	404,966.1	452,825.8	2,270,026.5
Cost ($ x 1000)	$ 3,637.0	$ 1,899.4	$ 400.3	$ 362.9	$ -	$ -	$ 5,124.3	$ 6,981.8	$ 4,693.8	$ 8,917.8	$ 8,968.9	$ 10,003.2	$ 50,989.3
Boardman													
Energy (MWh)	24,772.8	21,976.0	10,688.3	9,441.5	-	-	31,844.5	36,608.9	36,285.0	35,265.2	34,961.5	37,187.0	279,030.7
Cost ($ x 1000)	$ 474.2	$ 422.2	$ 213.8	$ 182.7	$ -	$ -	$ 574.5	$ 655.5	$ 647.4	$ 634.9	$ 627.2	$ 664.3	$ 5,096.6
Valmy													
Energy (MWh)	-	-	-	-	-	-	7,395.1	-	-	20,196.9	2,190.5	58,653.2	88,435.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 267.3	$ -	$ -	$ 712.2	$ 77.9	$ 2,015.6	$ 3,073.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	253.2	3.4	0.2	806.8	229.9	-	1,293.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 8.8	$ 0.1	$ 0.0	$ 29.1	$ 9.2	$ -	$ 47.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 459.5	$ 451.0	$ 437.1	$ 480.3	$ 446.6	$ 451.5	$ 5,108.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	54.0	-	-	54.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.0	$ -	$ -	$ 2.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.0	$ -	$ -	$ 2.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	32,726.9	978.4	-	1,617.9	47,272.9	25,541.9	498,570.8	372,916.8	239,986.4	40,822.9	118,062.4	363.9	1,378,861.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	66,468.6	30,537.7	28,374.5	31,797.4	76,565.1	87,831.2	561,003.6	435,122.6	265,319.9	71,293.1	152,008.0	39,449.3	1,845,771.0
Market Cost ($ x 1000)	$ 821.2	$ 25.3	$ -	$ 40.6	$ 1,009.0	$ 458.2	$ 13,440.5	$ 10,595.2	$ 7,187.6	$ 1,269.9	$ 3,742.8	$ 9.9	$ 38,600.2
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,664.0	$ 1,641.2	$ 1,142.4	$ 1,251.7	$ 2,187.0	$ 5,113.6	$ 18,422.0	$ 15,598.9	$ 8,574.1	$ 2,936.0	$ 5,968.0	$ 2,569.4	$ 68,068.4
Surplus Sales													
Energy (MWh)	114,666.2	179,912.7	204,982.2	124,604.9	43,550.0	162,594.0	-	1,363.1	21,447.9	47,539.2	8,577.2	357,433.1	1,266,670.5
Revenue Including Transmission Costs ($ x 1000)	$ 3,037.1	$ 3,928.1	$ 3,437.0	$ 2,178.9	$ 623.6	$ 1,280.7	$ -	$ 31.2	$ 554.7	$ 1,429.5	$ 267.4	$ 12,278.1	$ 29,046.3
Transmission Costs ($ x 1000)	$ 114.7	$ 179.9	$ 205.0	$ 124.6	$ 43.5	$ 162.6	$ -	$ 1.4	$ 21.4	$ 47.5	$ 8.6	$ 357.4	$ 1,266.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,922.5	$ 3,748.2	$ 3,232.0	$ 2,054.3	$ 580.0	$ 1,118.1	$ -	$ 29.9	$ 533.3	$ 1,382.0	$ 258.8	$ 11,920.7	$ 27,779.6
Net Power Supply Expenses ($ x 1000)	$ 4,198.6	$ 529.1	$ (1,076.5)	$ 179.3	$ 2,057.3	$ 4,432.2	$ 24,847.6	$ 23,657.3	$ 13,819.2	$ 12,301.2	$ 15,829.8	$ 3,783.4	$ 104,558.4

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1997

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,261,700.7	1,083,052.6	1,157,701.8	956,625.0	1,129,806.3	1,224,996.0	1,305,957.0	735,897.9	677,269.4	722,964.2	609,887.7	877,063.4	11,742,922.0
Bridger													
Energy (MWh)	102,960.4	39,172.4	13,748.9	13,676.8	-	42,601.8	116,489.6	257,964.5	122,654.2	374,284.3	386,995.5	442,076.0	1,912,624.3
Cost ($ x 1000)	$ 2,422.4	$ 904.2	$ 335.0	$ 333.5	$ -	$ 985.4	$ 2,711.7	$ 5,830.3	$ 2,788.8	$ 8,359.2	$ 8,608.2	$ 9,787.4	$ 43,066.1
Boardman													
Energy (MWh)	23,407.0	20,268.5	5,810.2	8,801.0	-	-	28,785.5	36,006.5	36,421.1	34,830.4	34,493.6	36,561.2	265,385.1
Cost ($ x 1000)	$ 449.7	$ 390.2	$ 117.4	$ 172.5	$ -	$ -	$ 522.0	$ 646.2	$ 649.5	$ 628.2	$ 620.0	$ 654.7	$ 4,850.5
Valmy													
Energy (MWh)	-	-	-	-	-	-	9,379.2	-	-	3,258.6	1,580.6	48,951.0	63,169.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 339.4	$ -	$ -	$ 115.9	$ 57.0	$ 1,686.1	$ 2,198.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	7.4	5.1	0.7	94.7	40.3	-	148.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.3	$ 0.2	$ 0.0	$ 3.3	$ 1.6	$ -	$ 5.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.9	$ 451.0	$ 437.1	$ 454.5	$ 439.0	$ 451.5	$ 5,066.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	2,706.1	1,658.0	79.9	7,644.7	30,206.0	38,137.0	138,082.0	353,717.0	305,217.7	15,902.2	38,395.9	20,739.7	952,486.3
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	36,447.8	31,217.2	28,454.4	37,824.2	59,498.1	100,426.3	200,514.8	415,922.9	330,551.3	46,372.4	72,341.5	59,825.1	1,419,396.1
Market Cost ($ x 1000)	$ 73.1	$ 43.8	$ 1.9	$ 193.0	$ 623.6	$ 651.6	$ 3,804.0	$ 9,907.1	$ 9,047.8	$ 467.3	$ 1,092.7	$ 557.8	$ 26,463.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 1,916.0	$ 1,659.7	$ 1,144.2	$ 1,404.1	$ 1,801.6	$ 5,307.0	$ 8,785.6	$ 14,910.8	$ 10,434.3	$ 2,133.4	$ 3,317.9	$ 3,117.3	$ 55,932.0
Surplus Sales													
Energy (MWh)	176,227.6	120,826.2	177,393.2	90,715.2	56,830.7	121,118.8	69,668.7	575.8	9,737.5	190,808.0	63,177.8	203,678.9	1,280,758.5
Revenue Including Transmission Costs ($ x 1000)	$ 3,993.5	$ 2,510.3	$ 2,869.4	$ 1,506.2	$ 801.2	$ 1,176.8	$ 1,349.4	$ 12.9	$ 240.0	$ 5,605.8	$ 1,948.3	$ 7,078.4	$ 29,092.2
Transmission Costs ($ x 1000)	$ 176.2	$ 120.8	$ 177.4	$ 90.7	$ 56.8	$ 121.1	$ 69.7	$ 0.6	$ 9.7	$ 190.8	$ 63.2	$ 203.7	$ 1,280.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,817.3	$ 2,389.5	$ 2,692.1	$ 1,415.5	$ 744.4	$ 1,055.6	$ 1,279.7	$ 12.3	$ 230.2	$ 5,415.0	$ 1,885.1	$ 6,874.8	$ 27,811.5
Net Power Supply Expenses ($ x 1000)	$ 1,316.5	$ 879.1	$ (696.4)	$ 930.9	$ 1,507.5	$ 5,673.4	$ 11,529.9	$ 21,826.1	$ 14,079.5	$ 6,276.2	$ 11,157.0	$ 8,822.4	$ 83,302.1

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1998

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,015,338.4	1,120,611.0	1,166,318.9	1,214,521.3	1,262,467.2	1,257,758.5	835,025.1	709,115.6	645,149.9	601,867.4	543,479.5	846,926.0	11,218,578.8
Bridger													
Energy (MWh)	316,229.2	220,289.9	115,968.6	52,350.2	13,584.1	43,389.8	334,492.9	382,080.8	325,013.1	401,775.3	412,653.3	461,436.6	3,079,263.9
Cost ($ x 1000)	$ 7,099.3	$ 4,964.8	$ 2,686.5	$ 1,215.7	$ 316.9	$ 1,003.6	$ 7,522.4	$ 8,553.8	$ 7,260.9	$ 8,925.7	$ 9,167.4	$ 10,176.0	$ 68,893.1
Boardman													
Energy (MWh)	28,510.2	25,116.4	28,862.8	13,244.2	-	21,396.4	40,534.4	38,404.4	36,364.1	36,018.4	31,943.7	35,011.3	335,406.2
Cost ($ x 1000)	$ 531.4	$ 470.3	$ 536.8	$ 248.7	$ -	$ 398.0	$ 715.6	$ 683.0	$ 648.7	$ 646.4	$ 581.0	$ 631.0	$ 6,090.8
Valmy													
Energy (MWh)	-	-	-	-	-	-	20,101.4	22,496.1	-	108,262.0	78,848.6	140,816.4	370,524.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 712.9	$ 772.8	$ -	$ 3,678.7	$ 2,716.9	$ 4,765.2	$ 12,646.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	1,474.2	411.6	0.4	313.9	-	-	2,200.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.9	$ 16.6	$ 0.0	$ 12.8	$ -	$ -	$ 87.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 508.6	$ 467.4	$ 437.1	$ 464.0	$ 437.5	$ 451.5	$ 5,148.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	80.8	-	-	25.1	-	-	105.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.2	$ -	$ -	$ 1.0	$ -	$ -	$ 4.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.2	$ -	$ -	$ 1.0	$ -	$ -	$ 4.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	36,557.9	285.1	12.3	-	9,284.9	20,367.0	297,980.1	233,784.8	152,229.5	15,354.2	23,811.7	10,108.4	799,776.0
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	70,299.6	29,844.4	28,386.8	30,179.5	38,577.0	82,656.3	360,412.8	295,990.7	177,563.0	45,824.4	57,757.3	49,193.8	1,266,685.7
Market Cost ($ x 1000)	$ 1,031.9	$ 8.7	$ 0.3	$ -	$ 218.6	$ 536.4	$ 9,394.1	$ 7,614.8	$ 5,034.3	$ 481.0	$ 661.2	$ 275.2	$ 25,256.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,874.7	$ 1,624.6	$ 1,142.7	$ 1,211.1	$ 1,396.6	$ 5,191.9	$ 14,375.6	$ 12,618.5	$ 6,420.8	$ 2,147.1	$ 2,886.4	$ 2,834.7	$ 54,724.7
Surplus Sales													
Energy (MWh)	182,100.5	342,986.4	311,247.8	384,082.0	182,150.3	158,343.9	696.8	3,277.7	26,913.1	203,085.9	82,513.4	272,576.2	2,149,973.9
Revenue Including Transmission Costs ($ x 1000)	$ 5,372.9	$ 8,961.4	$ 7,212.1	$ 8,580.9	$ 2,880.4	$ 2,285.3	$ 19.6	$ 95.3	$ 740.6	$ 6,951.7	$ 3,002.3	$ 10,483.2	$ 56,585.9
Transmission Costs ($ x 1000)	$ 182.1	$ 343.0	$ 311.2	$ 384.1	$ 182.2	$ 158.3	$ 0.7	$ 3.3	$ 26.9	$ 203.1	$ 82.5	$ 272.6	$ 2,150.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,190.8	$ 8,618.4	$ 6,900.9	$ 8,196.9	$ 2,698.3	$ 2,127.0	$ 18.9	$ 92.0	$ 713.7	$ 6,748.6	$ 2,919.8	$ 10,210.7	$ 54,435.9
Net Power Supply Expenses ($ x 1000)	$ 5,660.5	$ (1,244.3)	$ (2,135.7)	$ (5,085.0)	$ (534.5)	$ 4,903.2	$ 23,819.5	$ 23,003.5	$ 14,053.7	$ 9,114.3	$ 12,869.4	$ 8,647.8	$ 93,072.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

1999

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,062,419.8	1,170,791.7	1,169,666.0	986,128.3	1,023,595.3	1,262,358.0	757,392.3	606,413.9	666,558.6	521,033.6	482,568.0	829,056.8	10,537,982.3
Bridger													
Energy (MWh)	155,206.7	19,286.1	82,161.8	18,277.5	13,651.8	-	286,982.3	328,378.8	189,646.2	352,366.0	368,893.5	445,486.1	2,260,336.8
Cost ($ x 1000)	$ 3,631.7	$ 442.4	$ 1,946.5	$ 425.9	$ 318.3	$ -	$ 6,513.5	$ 7,382.5	$ 4,353.4	$ 7,894.7	$ 8,242.4	$ 9,855.9	$ 51,007.2
Boardman													
Energy (MWh)	22,196.9	23,671.1	25,863.8	11,824.5	-	4,195.5	36,540.0	38,585.1	32,678.5	30,092.4	28,969.9	35,300.6	289,918.2
Cost ($ x 1000)	$ 424.4	$ 448.1	$ 487.8	$ 227.0	$ -	$ 79.7	$ 654.4	$ 685.7	$ 592.2	$ 555.7	$ 535.4	$ 635.4	$ 5,325.9
Valmy													
Energy (MWh)	-	-	-	-	-	-	9,108.7	-	-	-	-	89,355.7	98,464.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 329.6	$ -	$ -	$ -	$ -	$ 3,080.3	$ 3,409.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	174.9	564.1	0.1	0.2	-	-	739.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.3	$ 20.7	$ 0.0	$ 0.0	$ -	$ -	$ 26.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 456.9	$ 471.5	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,088.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	55,857.7	236.8	-	2,787.7	94,777.1	39,057.4	438,805.1	410,070.1	262,154.9	83,305.8	131,876.7	25,501.5	1,544,430.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	89,599.5	29,796.0	28,374.5	32,967.3	124,069.2	101,346.7	501,237.8	472,276.0	287,488.5	113,776.0	165,822.2	64,586.9	2,011,340.5
Market Cost ($ x 1000)	$ 1,367.2	$ 6.2	$ -	$ 72.8	$ 2,363.7	$ 783.4	$ 12,148.3	$ 12,415.7	$ 7,676.5	$ 2,359.5	$ 3,778.1	$ 688.6	$ 43,660.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,210.1	$ 1,622.1	$ 1,142.4	$ 1,283.9	$ 3,541.6	$ 5,438.9	$ 17,129.8	$ 17,419.5	$ 9,063.0	$ 4,025.6	$ 6,003.3	$ 3,248.0	$ 73,128.2
Surplus Sales													
Energy (MWh)	81,139.3	190,662.2	277,772.4	122,986.3	28,891.4	121,025.7	-	1,005.1	19,192.2	26,259.8	4,079.9	202,984.1	1,075,998.4
Revenue Including Transmission Costs ($ x 1000)	$ 2,167.1	$ 4,179.7	$ 5,757.3	$ 2,407.1	$ 499.8	$ 1,156.4	$ -	$ 24.0	$ 459.2	$ 776.9	$ 127.0	$ 7,369.3	$ 24,923.7
Transmission Costs ($ x 1000)	$ 81.1	$ 190.7	$ 277.8	$ 123.0	$ 28.9	$ 121.0	$ -	$ 1.0	$ 19.2	$ 26.3	$ 4.1	$ 203.0	$ 1,076.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,085.9	$ 3,989.0	$ 5,479.5	$ 2,284.1	$ 470.9	$ 1,035.4	$ -	$ 23.0	$ 440.0	$ 750.6	$ 122.9	$ 7,166.3	$ 23,847.7
Net Power Supply Expenses ($ x 1000)	$ 5,526.1	$ (1,162.0)	$ (1,503.7)	$ 88.9	$ 3,839.3	$ 4,919.8	$ 25,084.3	$ 25,936.3	$ 14,005.7	$ 12,176.5	$ 15,095.7	$ 10,104.9	$ 114,111.8

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2000

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	801,248.3	1,083,683.8	1,100,910.4	1,164,466.1	836,146.4	686,743.2	631,892.8	531,793.8	564,467.5	528,479.8	419,510.9	501,401.4	8,850,744.3
Bridger													
Energy (MWh)	421,552.1	370,354.3	312,179.6	147,288.2	195,944.6	160,183.8	399,497.5	428,374.3	394,892.9	423,357.0	430,599.8	480,459.4	4,164,683.4
Cost ($ x 1000)	$ 9,375.5	$ 8,259.4	$ 7,002.1	$ 3,349.6	$ 4,396.5	$ 3,636.1	$ 8,918.1	$ 9,512.4	$ 8,777.7	$ 9,385.9	$ 9,512.8	$ 10,557.8	$ 92,684.0
Boardman													
Energy (MWh)	30,215.2	27,285.8	32,189.1	12,838.3	-	20,043.3	38,803.2	37,223.1	36,495.4	34,693.7	32,047.4	35,541.7	337,376.2
Cost ($ x 1000)	$ 557.5	$ 503.5	$ 587.8	$ 242.5	$ -	$ 374.1	$ 689.1	$ 664.9	$ 650.7	$ 626.1	$ 582.5	$ 639.1	$ 6,117.8
Valmy													
Energy (MWh)	16,080.2	4,577.2	-	-	-	-	75,402.1	110,643.4	58,220.5	137,128.0	137,676.7	155,201.7	694,929.8
Cost ($ x 1000)	$ 551.9	$ 158.9	$ -	$ -	$ -	$ -	$ 2,576.7	$ 3,762.7	$ 1,992.3	$ 4,645.0	$ 4,658.3	$ 5,226.9	$ 23,572.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	610.2	2,288.4	-	0.0	-	-	2,898.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 27.3	$ 104.9	$ -	$ 0.0	$ -	$ -	$ 132.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 477.9	$ 555.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,193.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	60.0	-	-	-	-	-	60.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.7	$ -	$ -	$ -	$ -	$ -	$ 2.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.7	$ -	$ -	$ -	$ -	$ -	$ 2.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	41,614.3	-	37.2	188.4	113,247.0	317,559.9	382,736.8	276,719.2	117,109.7	13,477.0	34,299.2	66,742.0	1,363,730.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	75,356.0	29,559.2	28,411.7	30,367.9	142,539.1	379,849.2	445,169.6	338,925.0	142,443.2	43,947.2	68,244.8	105,827.4	1,830,640.4
Market Cost ($ x 1000)	$ 1,072.5	$ -	$ 1.2	$ 5.6	$ 3,188.7	$ 8,386.6	$ 13,363.3	$ 10,121.1	$ 4,371.5	$ 405.4	$ 1,005.6	$ 2,669.6	$ 44,591.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,915.3	$ 1,615.9	$ 1,143.5	$ 1,216.8	$ 4,366.7	$ 13,042.0	$ 18,344.8	$ 15,124.9	$ 5,758.0	$ 2,071.5	$ 3,230.8	$ 5,229.1	$ 74,059.3
Surplus Sales													
Energy (MWh)	96,171.6	462,584.9	445,399.4	428,727.4	42,207.7	-	-	4,018.3	39,331.8	176,592.9	45,903.3	17,626.8	1,758,564.2
Revenue Including Transmission Costs ($ x 1000)	$ 3,271.3	$ 13,808.5	$ 11,711.4	$ 9,979.1	$ 1,069.6	$ -	$ -	$ 110.1	$ 1,158.2	$ 6,579.3	$ 1,786.7	$ 773.7	$ 50,247.9
Transmission Costs ($ x 1000)	$ 96.2	$ 462.6	$ 445.4	$ 428.7	$ 42.2	$ -	$ -	$ 4.0	$ 39.3	$ 176.6	$ 45.9	$ 17.6	$ 1,758.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,175.1	$ 13,345.9	$ 11,266.0	$ 9,550.4	$ 1,027.4	$ -	$ -	$ 106.1	$ 1,118.9	$ 6,402.7	$ 1,740.8	$ 756.1	$ 48,489.4
Net Power Supply Expenses ($ x 1000)	$ 10,570.9	$ (2,493.7)	$ (2,133.6)	$ (4,305.3)	$ 8,186.1	$ 17,488.8	$ 31,009.3	$ 29,514.6	$ 16,497.0	$ 10,777.1	$ 16,681.1	$ 21,348.4	$ 153,140.7

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2001

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,343.0	453,405.0	675,011.0	537,885.2	587,921.8	486,941.3	583,998.3	462,166.7	436,278.4	417,784.9	405,177.8	483,869.5	6,050,782.8
Bridger													
Energy (MWh)	483,381.7	435,615.8	477,513.3	393,767.7	305,753.6	288,713.4	479,854.5	477,165.7	439,362.3	464,698.0	460,191.1	483,152.1	5,189,169.1
Cost ($ x 1000)	$ 10,616.5	$ 9,569.3	$ 10,498.7	$ 8,699.8	$ 6,822.7	$ 6,469.6	$ 10,545.7	$ 10,491.7	$ 9,703.5	$ 10,241.5	$ 10,121.5	$ 10,611.9	$ 114,392.4
Boardman													
Energy (MWh)	37,792.8	35,177.1	38,756.6	17,000.2	-	22,976.2	39,769.6	38,873.9	36,522.1	37,640.4	36,492.9	36,137.3	377,139.1
Cost ($ x 1000)	$ 673.6	$ 624.4	$ 688.4	$ 306.2	$ -	$ 425.3	$ 703.9	$ 690.2	$ 651.1	$ 671.3	$ 650.6	$ 648.2	$ 6,733.1
Valmy													
Energy (MWh)	157,171.1	139,964.7	72,976.9	35,220.0	21,521.7	5,184.7	135,065.9	153,560.0	142,339.2	154,653.7	153,046.4	161,528.8	1,332,233.1
Cost ($ x 1000)	$ 5,289.5	$ 4,714.2	$ 2,495.3	$ 1,217.0	$ 745.3	$ 183.0	$ 4,577.5	$ 5,174.7	$ 4,808.9	$ 5,209.2	$ 5,148.7	$ 5,427.8	$ 44,991.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	4,326.3	6,541.8	906.5	509.7	-	-	12,284.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 230.5	$ 356.8	$ 48.9	$ 28.2	$ -	$ -	$ 664.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 681.1	$ 807.6	$ 486.0	$ 479.3	$ 437.5	$ 451.5	$ 5,725.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	788.3	578.6	-	-	-	-	1,366.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 42.5	$ 32.0	$ -	$ -	$ -	$ -	$ 74.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 42.5	$ 32.0	$ -	$ -	$ -	$ -	$ 74.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	32,894.2	10,414.4	144.0	17,368.5	196,756.3	380,715.0	286,648.8	254,238.5	135,604.3	5,145.0	8,148.6	68,028.8	1,396,106.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	66,635.9	39,973.7	28,518.5	47,548.1	226,048.4	443,004.3	349,081.6	316,444.4	160,937.8	35,615.2	42,094.2	107,114.2	1,863,016.2
Market Cost ($ x 1000)	$ 1,287.2	$ 446.6	$ 3.6	$ 557.2	$ 6,844.9	$ 11,650.1	$ 13,194.9	$ 12,171.9	$ 6,264.4	$ 258.3	$ 349.6	$ 3,267.0	$ 56,295.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,130.0	$ 2,062.5	$ 1,146.0	$ 1,768.3	$ 8,022.8	$ 16,305.6	$ 18,176.5	$ 17,175.6	$ 7,650.9	$ 1,924.4	$ 2,574.9	$ 5,826.5	$ 85,763.9
Surplus Sales													
Energy (MWh)	17,060.9	51,287.2	264,500.5	105,223.3	8,821.2	-	1,454.3	10,107.4	59,155.8	119,894.2	54,829.9	10,991.6	703,326.3
Revenue Including Transmission Costs ($ x 1000)	$ 692.1	$ 2,005.6	$ 9,042.3	$ 3,519.3	$ 217.3	$ -	$ 41.3	$ 312.7	$ 1,912.2	$ 4,838.3	$ 2,426.0	$ 538.2	$ 25,545.3
Transmission Costs ($ x 1000)	$ 17.1	$ 51.3	$ 264.5	$ 105.2	$ 8.8	$ -	$ 1.5	$ 10.1	$ 59.2	$ 119.9	$ 54.8	$ 11.0	$ 703.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 675.0	$ 1,954.3	$ 8,777.8	$ 3,414.1	$ 208.5	$ -	$ 39.8	$ 302.6	$ 1,853.0	$ 4,718.4	$ 2,371.2	$ 527.2	$ 24,841.9
Net Power Supply Expenses ($ x 1000)	$ 19,380.4	$ 15,330.5	$ 6,449.6	$ 9,013.6	$ 15,832.7	$ 23,820.1	$ 34,687.3	$ 34,069.3	$ 21,447.3	$ 13,807.3	$ 16,562.0	$ 22,438.7	$ 232,838.7

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2002

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,276.4	526,048.8	588,858.0	725,077.4	663,101.2	585,091.1	573,949.8	466,622.6	443,981.8	429,762.8	399,988.0	472,252.7	6,395,010.5
Bridger													
Energy (MWh)	443,094.1	381,124.7	378,844.2	344,948.2	293,438.6	261,361.0	442,079.4	463,240.1	412,329.4	436,797.0	432,684.5	483,170.7	4,773,111.9
Cost ($ x 1000)	$ 9,807.9	$ 8,475.6	$ 8,459.3	$ 7,680.0	$ 6,575.5	$ 5,864.4	$ 9,787.5	$ 10,212.2	$ 9,160.9	$ 9,681.5	$ 9,569.4	$ 10,612.3	$ 105,886.5
Boardman													
Energy (MWh)	30,098.4	27,030.7	28,938.3	15,073.4	-	19,546.5	37,824.7	37,780.2	33,606.1	33,948.3	31,405.6	37,603.6	332,855.8
Cost ($ x 1000)	$ 555.8	$ 499.6	$ 538.0	$ 276.7	$ -	$ 366.6	$ 674.1	$ 673.4	$ 606.4	$ 614.7	$ 572.7	$ 670.7	$ 6,048.7
Valmy													
Energy (MWh)	125,089.3	110,200.8	6,536.6	-	-	-	118,333.8	143,454.1	106,608.6	141,668.8	139,970.1	164,630.0	1,056,492.1
Cost ($ x 1000)	$ 4,236.9	$ 3,740.4	$ 232.3	$ -	$ -	$ -	$ 4,017.0	$ 4,849.1	$ 3,634.9	$ 4,793.3	$ 4,733.5	$ 5,526.4	$ 35,763.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	1,361.4	6,032.7	646.4	-	-	-	8,040.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68.2	$ 310.1	$ 32.9	$ -	$ -	$ -	$ 411.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 518.9	$ 761.0	$ 470.0	$ 451.2	$ 437.5	$ 451.5	$ 5,472.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	378.0	-	-	-	-	378.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19.7	$ -	$ -	$ -	$ -	$ 19.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19.7	$ -	$ -	$ -	$ -	$ 19.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	108,860.3	48,550.1	61,242.2	7,635.7	162,057.5	318,542.6	355,462.3	273,311.4	155,897.4	11,361.5	40,513.6	73,630.1	1,617,064.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	142,602.0	78,109.3	89,616.7	37,815.2	191,349.6	380,831.8	417,895.0	335,517.3	181,230.9	41,831.7	74,459.1	112,715.5	2,083,974.3
Market Cost ($ x 1000)	$ 3,231.5	$ 1,231.3	$ 1,667.7	$ 213.3	$ 5,008.9	$ 8,796.7	$ 13,964.9	$ 11,709.5	$ 6,288.8	$ 369.5	$ 1,245.3	$ 3,571.7	$ 57,299.2
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 5,074.4	$ 2,847.2	$ 2,810.1	$ 1,424.4	$ 6,186.9	$ 13,452.2	$ 18,946.4	$ 16,713.2	$ 7,675.3	$ 2,035.6	$ 3,470.5	$ 6,131.2	$ 86,767.3
Surplus Sales													
Energy (MWh)	12,874.5	69,644.4	64,502.3	196,703.9	15,455.0	1.0	-	7,794.6	21,202.3	92,984.6	36,322.7	9,571.7	527,057.2
Revenue Including Transmission Costs ($ x 1000)	$ 475.7	$ 2,634.4	$ 1,992.3	$ 5,916.3	$ 341.1	$ 0.0	$ -	$ 226.2	$ 643.1	$ 3,617.5	$ 1,547.5	$ 449.9	$ 17,844.1
Transmission Costs ($ x 1000)	$ 12.9	$ 69.6	$ 64.5	$ 196.7	$ 15.5	$ 0.0	$ -	$ 7.8	$ 21.2	$ 93.0	$ 36.3	$ 9.6	$ 527.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 462.8	$ 2,564.8	$ 1,927.7	$ 5,719.6	$ 325.6	$ 0.0	$ -	$ 218.4	$ 621.9	$ 3,524.5	$ 1,511.2	$ 440.3	$ 17,317.1
Net Power Supply Expenses ($ x 1000)	$ 19,557.9	$ 13,312.4	$ 10,511.0	$ 4,097.8	$ 12,887.0	$ 20,119.8	$ 33,943.9	$ 33,010.1	$ 20,925.6	$ 14,051.8	$ 17,272.4	$ 22,951.8	$ 222,641.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2003

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	540,878.9	558,135.4	528,137.4	595,096.9	845,654.6	745,203.7	557,057.9	484,106.6	444,003.9	437,568.8	400,987.7	477,382.9	6,614,214.5
Bridger													
Energy (MWh)	483,371.9	435,303.5	476,900.6	384,720.6	292,653.8	277,480.7	467,088.6	477,526.9	433,752.8	454,070.0	458,163.6	483,405.7	5,124,438.7
Cost ($ x 1000)	$ 10,616.3	$ 9,563.0	$ 10,486.4	$ 8,518.3	$ 6,548.7	$ 6,222.0	$ 10,289.5	$ 10,499.0	$ 9,590.9	$ 10,028.2	$ 10,080.8	$ 10,617.0	$ 113,060.0
Boardman													
Energy (MWh)	37,482.0	33,352.4	38,268.5	16,631.6	-	22,270.6	38,051.5	38,717.4	36,484.5	36,264.7	36,095.0	38,821.3	372,439.4
Cost ($ x 1000)	$ 668.8	$ 596.4	$ 680.9	$ 300.6	$ -	$ 414.5	$ 677.6	$ 687.8	$ 650.5	$ 650.2	$ 644.5	$ 689.3	$ 6,661.1
Valmy													
Energy (MWh)	156,088.4	134,726.9	64,953.3	12,087.4	-	-	126,348.8	151,940.5	141,928.6	149,119.8	151,164.3	167,723.1	1,256,081.0
Cost ($ x 1000)	$ 5,255.1	$ 4,547.8	$ 2,227.0	$ 422.1	$ -	$ -	$ 4,287.2	$ 5,123.3	$ 4,795.9	$ 5,033.6	$ 5,088.9	$ 5,624.8	$ 42,405.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,285.4	5,574.6	665.9	-	-	-	9,525.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 171.7	$ 299.0	$ 35.3	$ -	$ -	$ -	$ 506.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 622.3	$ 749.8	$ 472.5	$ 451.2	$ 437.5	$ 451.5	$ 5,567.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	69.6	508.7	-	-	-	-	578.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.7	$ 27.7	$ -	$ -	$ -	$ -	$ 31.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.7	$ 27.7	$ -	$ -	$ -	$ -	$ 31.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	27,170.0	99.7	2,129.2	6,652.9	26,432.0	153,898.5	337,143.3	236,183.9	130,959.9	4,433.7	11,290.2	66,067.4	1,002,460.7
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	60,911.8	29,659.0	30,503.7	36,832.4	55,724.1	216,187.8	399,576.1	298,389.8	156,293.5	34,903.9	45,235.7	105,152.8	1,469,370.4
Market Cost ($ x 1000)	$ 1,016.5	$ 2.7	$ 72.7	$ 180.4	$ 697.5	$ 4,394.1	$ 14,468.8	$ 11,051.6	$ 5,923.8	$ 185.2	$ 472.4	$ 3,388.9	$ 41,854.5
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,859.4	$ 1,618.5	$ 1,215.0	$ 1,391.5	$ 1,875.4	$ 9,049.6	$ 19,450.3	$ 16,055.3	$ 7,310.3	$ 1,851.3	$ 2,697.7	$ 5,948.3	$ 71,322.7
Surplus Sales													
Energy (MWh)	30,466.8	138,320.4	110,488.7	119,167.2	61,588.8	14,315.6	38.4	11,539.8	55,938.0	120,910.6	49,472.9	11,687.2	723,934.4
Revenue Including Transmission Costs ($ x 1000)	$ 1,223.8	$ 5,400.0	$ 3,720.7	$ 3,855.9	$ 1,888.5	$ 424.0	$ 1.1	$ 351.8	$ 1,812.7	$ 4,867.4	$ 2,167.7	$ 566.1	$ 26,279.6
Transmission Costs ($ x 1000)	$ 30.5	$ 138.3	$ 110.5	$ 119.2	$ 61.6	$ 14.3	$ 0.0	$ 11.5	$ 55.9	$ 120.9	$ 49.5	$ 11.7	$ 723.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,193.4	$ 5,261.6	$ 3,610.2	$ 3,736.8	$ 1,827.0	$ 409.7	$ 1.1	$ 340.2	$ 1,756.8	$ 4,746.5	$ 2,118.2	$ 554.4	$ 25,555.7
Net Power Supply Expenses ($ x 1000)	$ 18,552.1	$ 11,378.6	$ 11,398.2	$ 7,331.9	$ 7,047.5	$ 15,713.0	$ 35,329.5	$ 32,802.6	$ 21,063.2	$ 13,268.0	$ 16,831.2	$ 22,776.5	$ 213,492.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2004

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,248.9	445,920.5	732,638.5	643,064.9	718,697.6	576,933.5	542,765.8	462,530.3	442,510.2	416,569.1	397,319.6	467,244.5	6,366,443.3
Bridger													
Energy (MWh)	476,727.1	436,519.2	468,086.1	350,940.4	295,924.3	279,975.7	473,837.8	473,391.1	434,137.3	454,863.4	458,828.1	483,405.1	5,086,635.5
Cost ($ x 1000)	$ 10,482.9	$ 9,587.4	$ 10,309.5	$ 7,817.5	$ 6,625.4	$ 6,272.1	$ 10,424.9	$ 10,416.0	$ 9,598.6	$ 10,044.1	$ 10,094.2	$ 10,617.0	$ 112,289.5
Boardman													
Energy (MWh)	34,532.3	34,765.4	37,762.2	14,853.8	-	23,427.3	38,908.8	38,301.3	36,296.7	36,305.0	36,591.3	39,761.1	371,505.1
Cost ($ x 1000)	$ 623.7	$ 618.1	$ 673.1	$ 273.4	$ -	$ 435.2	$ 690.7	$ 681.4	$ 647.6	$ 650.8	$ 652.1	$ 703.7	$ 6,649.8
Valmy													
Energy (MWh)	150,429.2	138,179.6	33,910.6	-	-	-	133,036.0	150,369.0	142,215.9	148,476.8	151,969.7	168,304.8	1,216,891.6
Cost ($ x 1000)	$ 5,075.4	$ 4,657.5	$ 1,167.4	$ -	$ -	$ -	$ 4,512.3	$ 5,073.4	$ 4,804.9	$ 5,013.2	$ 5,114.5	$ 5,643.3	$ 41,061.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	4,918.7	5,088.6	735.4	-	-	-	10,742.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 257.5	$ 273.4	$ 39.1	$ -	$ -	$ -	$ 570.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 708.2	$ 724.2	$ 476.2	$ 451.2	$ 437.5	$ 451.5	$ 5,631.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	143.7	312.2	-	-	-	-	455.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.6	$ 17.0	$ -	$ -	$ -	$ -	$ 24.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.6	$ 17.0	$ -	$ -	$ -	$ -	$ 24.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	46,778.5	13,399.5	573.5	12,985.5	108,238.5	304,433.6	335,440.2	263,558.3	131,385.0	7,210.3	11,337.9	73,576.7	1,308,917.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	80,520.2	42,958.8	28,948.0	43,165.1	137,530.6	366,722.9	397,872.9	325,764.1	156,718.5	37,680.5	45,283.5	112,662.1	1,775,827.2
Market Cost ($ x 1000)	$ 1,557.9	$ 566.8	$ 15.8	$ 347.9	$ 3,375.1	$ 9,168.9	$ 14,792.8	$ 12,088.7	$ 5,922.5	$ 306.0	$ 494.3	$ 3,846.9	$ 52,483.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,400.7	$ 2,182.7	$ 1,158.1	$ 1,559.0	$ 4,553.0	$ 13,824.4	$ 19,774.4	$ 17,092.4	$ 7,309.0	$ 1,972.1	$ 2,719.5	$ 6,406.4	$ 81,951.8
Surplus Sales													
Energy (MWh)	14,183.2	45,492.6	273,064.6	125,813.4	19,713.6	237.1	50.9	10,528.4	55,422.4	102,879.1	47,819.9	10,580.7	705,785.9
Revenue Including Transmission Costs ($ x 1000)	$ 554.9	$ 1,746.1	$ 8,955.9	$ 4,030.4	$ 491.8	$ 7.3	$ 1.5	$ 317.7	$ 1,790.6	$ 4,106.7	$ 2,102.1	$ 505.3	$ 24,610.4
Transmission Costs ($ x 1000)	$ 14.2	$ 45.5	$ 273.1	$ 125.8	$ 19.7	$ 0.2	$ 0.1	$ 10.5	$ 55.4	$ 102.9	$ 47.8	$ 10.6	$ 705.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 540.8	$ 1,700.6	$ 8,682.8	$ 3,904.5	$ 472.1	$ 7.1	$ 1.5	$ 307.2	$ 1,735.2	$ 4,003.8	$ 2,054.3	$ 494.7	$ 23,904.6
Net Power Supply Expenses ($ x 1000)	$ 19,387.7	$ 15,659.5	$ 5,024.4	$ 6,181.6	$ 11,156.7	$ 20,961.3	$ 36,116.6	$ 33,697.1	$ 21,101.2	$ 14,127.6	$ 16,963.5	$ 23,327.2	$ 223,704.5

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2005

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,432.0	404,612.4	475,250.4	678,000.7	986,009.5	660,247.7	557,733.0	460,538.7	433,288.7	443,397.6	407,259.4	534,239.3	6,561,009.3
Bridger													
Energy (MWh)	478,944.2	436,657.8	474,711.6	357,117.6	290,368.9	275,424.0	476,415.4	475,064.7	433,906.7	455,080.3	459,167.8	483,401.6	5,096,260.7
Cost ($ x 1000)	$ 10,527.4	$ 9,590.2	$ 10,442.5	$ 7,955.9	$ 6,502.8	$ 6,169.7	$ 10,476.7	$ 10,449.6	$ 9,594.0	$ 10,048.4	$ 10,101.0	$ 10,616.9	$ 112,475.1
Boardman													
Energy (MWh)	35,143.1	35,186.4	37,912.4	15,270.2	-	23,394.1	39,350.9	38,067.2	36,568.5	36,260.5	36,598.4	39,917.2	373,668.9
Cost ($ x 1000)	$ 633.0	$ 624.5	$ 675.4	$ 279.7	$ -	$ 434.7	$ 697.5	$ 677.8	$ 651.8	$ 650.1	$ 652.2	$ 706.1	$ 6,683.0
Valmy													
Energy (MWh)	149,286.9	140,282.3	55,512.5	-	-	-	132,776.6	150,733.8	141,777.7	148,554.3	151,817.3	168,396.2	1,239,137.6
Cost ($ x 1000)	$ 5,034.3	$ 4,724.3	$ 1,907.4	$ -	$ -	$ -	$ 4,506.0	$ 5,084.9	$ 4,791.1	$ 5,015.7	$ 5,109.7	$ 5,646.2	$ 41,819.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	4,144.9	5,442.9	840.5	44.9	-	-	10,473.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 217.0	$ 292.4	$ 44.7	$ 2.4	$ -	$ -	$ 556.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 667.7	$ 743.3	$ 481.8	$ 453.6	$ 437.5	$ 451.5	$ 5,617.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	324.8	472.7	-	-	-	-	797.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.2	$ 25.8	$ -	$ -	$ -	$ -	$ 43.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.2	$ 25.8	$ -	$ -	$ -	$ -	$ 43.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	46,322.3	29,639.4	13,830.5	5,604.0	4,163.4	233,586.5	318,499.7	263,989.4	138,005.3	3,888.9	8,978.0	32,175.0	1,098,682.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	80,064.1	59,198.7	42,205.0	35,783.6	33,455.6	295,875.7	380,932.5	326,195.3	163,338.8	34,359.1	42,923.6	71,260.4	1,565,592.2
Market Cost ($ x 1000)	$ 1,588.6	$ 1,270.2	$ 473.5	$ 144.5	$ 101.9	$ 7,077.1	$ 14,227.1	$ 12,145.7	$ 6,272.0	$ 162.2	$ 400.2	$ 1,460.4	$ 45,323.3
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 3,431.4	$ 2,886.1	$ 1,615.8	$ 1,355.7	$ 1,279.8	$ 11,732.6	$ 19,208.6	$ 17,149.5	$ 7,658.5	$ 1,828.3	$ 2,625.4	$ 4,019.9	$ 74,791.5
Surplus Sales													
Energy (MWh)	15,597.1	23,090.2	57,317.8	159,963.2	177,388.5	8,118.7	246.3	11,287.2	52,530.1	126,681.1	55,594.0	36,415.7	724,229.9
Revenue Including Transmission Costs ($ x 1000)	$ 614.5	$ 875.2	$ 1,899.0	$ 5,123.9	$ 5,133.9	$ 243.3	$ 6.8	$ 332.7	$ 1,682.1	$ 5,115.4	$ 2,460.9	$ 1,925.7	$ 25,413.4
Transmission Costs ($ x 1000)	$ 15.6	$ 23.1	$ 57.3	$ 160.0	$ 177.4	$ 8.1	$ 0.2	$ 11.3	$ 52.5	$ 126.7	$ 55.6	$ 36.4	$ 724.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 598.9	$ 852.1	$ 1,841.7	$ 4,963.9	$ 4,956.5	$ 235.2	$ 6.5	$ 321.4	$ 1,629.5	$ 4,988.7	$ 2,405.3	$ 1,889.3	$ 24,689.1
Net Power Supply Expenses ($ x 1000)	$ 19,373.1	$ 17,287.4	$ 13,198.5	$ 5,063.7	$ 3,276.5	$ 18,538.4	$ 35,567.1	$ 33,809.4	$ 21,547.6	$ 13,007.5	$ 16,520.6	$ 19,551.3	$ 216,741.0

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2006

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	800,627.7	976,545.6	1,135,252.0	1,101,740.3	1,278,862.4	946,475.4	629,080.8	561,950.0	510,672.8	509,605.4	403,951.6	593,441.7	9,448,205.9
Bridger													
Energy (MWh)	366,465.4	324,509.3	130,313.2	52,096.1	13,639.9	-	344,621.1	414,251.1	359,771.7	431,716.8	445,406.3	481,623.1	3,364,414.0
Cost ($ x 1000)	$ 8,196.1	$ 7,248.3	$ 2,984.3	$ 1,207.9	$ 318.0	$ -	$ 7,734.3	$ 9,229.0	$ 8,017.5	$ 9,579.5	$ 9,824.8	$ 10,581.2	$ 74,920.9
Boardman													
Energy (MWh)	28,867.5	27,513.4	27,754.6	12,899.6	-	21,637.4	38,983.3	38,505.6	36,181.8	36,073.3	35,781.4	39,225.0	343,422.9
Cost ($ x 1000)	$ 536.9	$ 507.0	$ 519.9	$ 243.4	$ -	$ 404.8	$ 691.8	$ 684.5	$ 645.9	$ 647.3	$ 639.7	$ 695.5	$ 6,216.7
Valmy													
Energy (MWh)	-	-	-	-	-	-	12,992.2	92,303.3	12,196.3	122,441.8	139,403.2	153,967.9	533,304.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 456.9	$ 3,164.7	$ 423.3	$ 4,156.2	$ 4,710.7	$ 5,187.8	$ 18,099.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	2,002.7	2,921.7	5.2	23.2	-	-	4,952.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 82.4	$ 123.3	$ 0.2	$ 1.0	$ -	$ -	$ 207.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 533.1	$ 574.2	$ 437.3	$ 452.2	$ 437.5	$ 451.5	$ 5,268.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	18.0	102.0	-	-	-	-	120.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.8	$ 4.4	$ -	$ -	$ -	$ -	$ 5.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.8	$ 4.4	$ -	$ -	$ -	$ -	$ 5.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	86,897.8	1,348.7	480.4	-	7,496.6	220,208.4	501,302.2	274,607.5	218,686.5	7,311.3	24,163.6	22,996.9	1,365,499.8
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	120,639.6	30,908.0	28,854.9	30,179.5	36,788.7	282,497.6	563,734.9	336,813.4	244,020.0	37,781.5	58,109.1	62,082.3	1,832,409.5
Market Cost ($ x 1000)	$ 2,236.1	$ 42.0	$ 13.2	$ -	$ 195.7	$ 5,074.0	$ 16,160.5	$ 9,493.9	$ 7,423.9	$ 199.6	$ 755.2	$ 806.7	$ 42,400.8
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 4,079.0	$ 1,657.9	$ 1,155.5	$ 1,211.1	$ 1,373.6	$ 9,729.4	$ 21,142.0	$ 14,497.6	$ 8,810.4	$ 1,865.7	$ 2,980.4	$ 3,366.2	$ 71,868.9
Surplus Sales													
Energy (MWh)	68,322.2	306,605.8	293,882.8	270,689.7	196,824.9	3,782.2	-	1,627.6	5,666.1	146,638.2	40,490.8	69,547.5	1,404,077.9
Revenue Including Transmission Costs ($ x 1000)	$ 2,160.2	$ 8,634.1	$ 7,018.9	$ 6,010.6	$ 3,298.1	$ 78.3	$ -	$ 43.5	$ 149.1	$ 5,201.4	$ 1,532.0	$ 2,973.6	$ 37,099.8
Transmission Costs ($ x 1000)	$ 68.3	$ 306.6	$ 293.9	$ 270.7	$ 196.8	$ 3.8	$ -	$ 1.6	$ 5.7	$ 146.6	$ 40.5	$ 69.5	$ 1,404.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,091.9	$ 8,327.5	$ 6,725.0	$ 5,739.9	$ 3,101.3	$ 74.5	$ -	$ 41.8	$ 143.4	$ 5,054.8	$ 1,491.5	$ 2,904.0	$ 35,695.7
Net Power Supply Expenses ($ x 1000)	$ 11,065.9	$ 1,400.2	$ (1,666.3)	$ (2,641.2)	$ (959.3)	$ 10,496.3	$ 30,558.9	$ 28,112.4	$ 18,190.9	$ 11,646.1	$ 17,101.6	$ 17,378.2	$ 140,683.7

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2007

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	646,469.1	573,286.0	637,148.7	558,055.8	646,454.3	536,064.0	575,740.3	495,426.0	443,996.2	447,559.7	394,381.3	490,121.8	6,444,703.1
Bridger													
Energy (MWh)	452,307.8	412,564.2	443,020.9	366,884.2	296,561.8	267,896.9	447,195.3	468,903.6	429,733.5	458,702.8	459,576.1	483,367.8	4,986,714.9
Cost ($ x 1000)	$ 9,992.8	$ 9,106.6	$ 9,791.7	$ 8,160.3	$ 6,627.1	$ 6,007.5	$ 9,890.2	$ 10,325.9	$ 9,510.2	$ 10,121.2	$ 10,109.2	$ 10,616.2	$ 110,258.8
Boardman													
Energy (MWh)	30,896.4	29,513.3	33,560.1	15,458.3	-	19,967.2	37,452.3	38,034.5	36,492.3	37,115.3	37,012.6	39,831.8	355,334.2
Cost ($ x 1000)	$ 568.0	$ 537.6	$ 608.8	$ 282.6	$ -	$ 375.9	$ 668.4	$ 677.3	$ 650.6	$ 663.2	$ 658.6	$ 704.8	$ 6,395.8
Valmy													
Energy (MWh)	132,426.5	128,715.9	13,325.9	-	-	-	119,914.5	146,507.1	141,439.9	150,791.2	153,184.9	168,727.8	1,155,033.6
Cost ($ x 1000)	$ 4,479.6	$ 4,356.9	$ 469.0	$ -	$ -	$ -	$ 4,069.3	$ 4,950.7	$ 4,780.3	$ 5,086.6	$ 5,153.2	$ 5,656.7	$ 39,002.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	1,149.0	4,833.3	557.2	70.4	-	-	6,609.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 59.1	$ 255.3	$ 29.1	$ 3.8	$ -	$ -	$ 347.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 509.8	$ 706.1	$ 466.2	$ 455.0	$ 437.5	$ 451.5	$ 5,408.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	183.7	-	-	-	-	183.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.8	$ -	$ -	$ -	$ -	$ 9.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.8	$ -	$ -	$ -	$ -	$ 9.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	34,062.2	10,760.0	11,366.9	30,160.4	172,484.5	360,615.4	347,564.3	240,994.0	131,722.2	3,384.5	11,603.9	57,047.4	1,411,765.6
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	67,803.9	40,319.3	39,741.4	60,339.9	201,776.6	422,904.7	409,997.0	303,199.8	157,055.7	33,854.7	45,549.5	96,132.8	1,878,675.3
Market Cost ($ x 1000)	$ 891.4	$ 286.2	$ 346.1	$ 862.4	$ 5,648.7	$ 10,040.3	$ 13,925.1	$ 10,678.3	$ 5,817.4	$ 137.4	$ 517.7	$ 2,928.1	$ 52,079.0
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,734.2	$ 1,902.1	$ 1,488.4	$ 2,073.5	$ 6,826.7	$ 14,695.8	$ 18,906.6	$ 15,682.1	$ 7,203.9	$ 1,803.5	$ 2,742.9	$ 5,487.6	$ 81,547.2
Surplus Sales													
Energy (MWh)	81,619.4	131,534.8	138,511.2	74,532.6	12,362.5	-	0.5	11,856.3	52,082.5	137,081.5	47,534.8	17,387.7	704,504.0
Revenue Including Transmission Costs ($ x 1000)	$ 3,173.0	$ 5,029.4	$ 4,366.0	$ 2,373.5	$ 289.5	$ -	$ 0.0	$ 357.0	$ 1,676.4	$ 5,489.1	$ 2,072.4	$ 862.4	$ 25,688.6
Transmission Costs ($ x 1000)	$ 81.6	$ 131.5	$ 138.5	$ 74.5	$ 12.4	$ -	$ 0.0	$ 11.9	$ 52.1	$ 137.1	$ 47.5	$ 17.4	$ 704.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,091.4	$ 4,897.9	$ 4,227.5	$ 2,298.9	$ 277.1	$ -	$ 0.0	$ 345.2	$ 1,624.3	$ 5,352.0	$ 2,024.8	$ 845.1	$ 24,984.1
Net Power Supply Expenses ($ x 1000)	$ 15,029.0	$ 11,319.8	$ 8,529.5	$ 8,653.7	$ 13,627.0	$ 21,515.8	$ 34,044.3	$ 32,006.8	$ 20,987.1	$ 12,777.4	$ 17,076.4	$ 22,071.8	$ 217,638.6

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2008

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,338.0	553,844.4	624,168.9	631,243.9	947,389.9	867,363.7	647,441.9	530,674.3	446,026.7	501,236.5	409,422.9	471,868.0	7,151,019.1
Bridger													
Energy (MWh)	432,372.9	375,205.0	329,980.9	313,493.9	248,345.4	216,621.4	419,850.6	445,794.9	398,422.1	430,347.6	429,666.0	482,923.2	4,523,023.9
Cost ($ x 1000)	$ 9,592.7	$ 8,356.8	$ 7,385.2	$ 6,988.8	$ 5,565.3	$ 4,877.0	$ 9,338.6	$ 9,862.1	$ 8,867.0	$ 9,552.0	$ 9,508.9	$ 10,607.3	$ 100,501.6
Boardman													
Energy (MWh)	29,848.4	26,730.6	28,079.6	14,820.8	-	20,501.4	37,897.6	37,650.5	33,697.0	33,699.4	31,230.0	36,855.8	331,011.2
Cost ($ x 1000)	$ 551.9	$ 495.0	$ 524.8	$ 272.9	$ -	$ 383.8	$ 675.2	$ 671.4	$ 607.8	$ 610.9	$ 570.0	$ 659.2	$ 6,023.0
Valmy													
Energy (MWh)	82,818.0	49,743.3	3,651.4	-	-	-	96,779.1	124,830.8	92,239.0	138,162.1	138,893.7	161,311.8	888,429.1
Cost ($ x 1000)	$ 2,842.5	$ 1,707.0	$ 132.1	$ -	$ -	$ -	$ 3,305.4	$ 4,242.7	$ 3,154.5	$ 4,677.9	$ 4,699.2	$ 5,421.0	$ 30,182.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	232.3	2,530.1	402.7	-	-	-	3,165.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.1	$ 123.7	$ 19.5	$ -	$ -	$ -	$ 154.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 461.7	$ 574.5	$ 456.6	$ 451.2	$ 437.5	$ 451.5	$ 5,215.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	154,723.5	58,287.5	86,475.4	33,314.4	18,767.7	111,845.8	326,831.7	245,676.0	176,586.1	9,582.1	37,955.7	77,414.1	1,337,460.0
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	188,465.3	87,846.7	114,849.9	63,493.9	48,059.8	174,135.1	389,264.4	307,881.9	201,919.6	40,052.3	71,901.3	116,499.5	1,804,369.7
Market Cost ($ x 1000)	$ 4,612.7	$ 1,511.2	$ 2,447.7	$ 940.3	$ 506.3	$ 2,724.2	$ 11,964.1	$ 9,807.3	$ 6,681.3	$ 261.6	$ 1,112.4	$ 3,524.5	$ 46,093.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 6,455.6	$ 3,127.1	$ 3,590.1	$ 2,151.4	$ 1,684.3	$ 7,379.6	$ 16,945.6	$ 14,811.1	$ 8,067.8	$ 1,927.7	$ 3,337.7	$ 6,084.0	$ 75,561.9
Surplus Sales													
Energy (MWh)	5,561.6	40,502.5	72,446.7	96,850.9	111,353.6	31,788.7	20.9	4,131.0	15,508.7	152,476.5	38,931.1	8,658.0	578,230.2
Revenue Including Transmission Costs ($ x 1000)	$ 217.0	$ 1,507.1	$ 2,213.5	$ 2,889.9	$ 3,034.9	$ 875.6	$ 0.6	$ 113.5	$ 483.2	$ 5,926.3	$ 1,588.8	$ 391.2	$ 19,241.6
Transmission Costs ($ x 1000)	$ 5.6	$ 40.5	$ 72.4	$ 96.9	$ 111.4	$ 31.8	$ 0.0	$ 4.1	$ 15.5	$ 152.5	$ 38.9	$ 8.7	$ 578.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 211.4	$ 1,466.6	$ 2,141.0	$ 2,793.0	$ 2,923.5	$ 843.8	$ 0.6	$ 109.4	$ 467.7	$ 5,773.9	$ 1,549.9	$ 382.6	$ 18,663.4
Net Power Supply Expenses ($ x 1000)	$ 19,577.1	$ 12,533.8	$ 9,890.3	$ 7,056.3	$ 4,776.4	$ 12,233.2	$ 30,726.0	$ 30,052.4	$ 20,686.0	$ 11,445.9	$ 17,003.3	$ 22,840.5	$ 198,821.3

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2009

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	520,347.7	590,869.7	602,904.2	980,187.4	1,107,702.1	1,134,423.2	962,544.6	550,918.0	526,615.6	548,127.1	434,481.4	577,900.2	8,537,021.2
Bridger													
Energy (MWh)	435,850.9	395,509.2	346,225.1	246,647.5	204,272.9	124,528.1	387,959.6	433,958.0	403,106.0	438,913.8	456,560.7	483,170.0	4,356,701.8
Cost ($ x 1000)	$ 9,662.5	$ 8,764.3	$ 7,725.9	$ 5,517.4	$ 4,582.1	$ 2,829.4	$ 8,671.8	$ 9,624.5	$ 8,946.3	$ 9,709.2	$ 10,048.7	$ 10,612.2	$ 96,694.4
Boardman													
Energy (MWh)	30,087.1	29,154.2	32,941.6	14,784.6	-	18,237.0	36,985.1	37,686.6	36,450.9	36,936.0	36,652.3	39,315.3	349,230.7
Cost ($ x 1000)	$ 555.6	$ 532.1	$ 599.3	$ 272.3	$ -	$ 344.3	$ 661.2	$ 672.0	$ 650.0	$ 660.5	$ 653.1	$ 696.9	$ 6,297.2
Valmy													
Energy (MWh)	37,628.3	32,366.6	1,720.2	-	-	-	49,735.2	117,423.1	74,594.6	142,777.4	147,613.8	165,111.7	768,970.8
Cost ($ x 1000)	$ 1,294.2	$ 1,117.9	$ 62.2	$ -	$ -	$ -	$ 1,704.1	$ 3,992.8	$ 2,550.4	$ 4,828.9	$ 4,976.2	$ 5,541.7	$ 26,068.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	-	2,537.1	-	160.1	-	-	2,697.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 118.9	$ -	$ 7.6	$ -	$ -	$ 126.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 569.7	$ 437.1	$ 458.8	$ 437.5	$ 451.5	$ 5,187.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	191,307.8	30,738.4	82,139.6	1,176.5	6,684.7	22,670.3	112,427.2	244,651.6	127,660.5	5,349.3	3,804.7	16,280.5	844,891.1
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	225,049.5	60,297.6	110,514.1	31,356.0	35,976.9	84,959.5	174,859.9	306,857.4	152,994.0	35,819.5	37,750.3	55,365.9	1,311,800.8
Market Cost ($ x 1000)	$ 5,812.1	$ 825.1	$ 2,528.1	$ 36.8	$ 192.2	$ 540.2	$ 3,867.0	$ 9,215.9	$ 4,819.8	$ 174.9	$ 134.6	$ 651.1	$ 28,797.7
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 7,655.0	$ 2,441.0	$ 3,670.4	$ 1,247.9	$ 1,370.1	$ 5,195.6	$ 8,848.5	$ 14,219.7	$ 6,206.3	$ 1,841.0	$ 2,359.8	$ 3,210.5	$ 58,265.8
Surplus Sales													
Energy (MWh)	684.8	55,336.9	66,037.1	346,761.3	215,511.7	115,292.9	20,627.6	4,150.0	36,571.6	211,725.8	70,892.9	60,069.6	1,203,662.2
Revenue Including Transmission Costs ($ x 1000)	$ 25.9	$ 1,924.8	$ 2,018.1	$ 9,103.3	$ 5,631.7	$ 2,690.1	$ 620.6	$ 114.9	$ 1,072.7	$ 8,083.0	$ 2,836.0	$ 2,760.8	$ 36,882.0
Transmission Costs ($ x 1000)	$ 0.7	$ 55.3	$ 66.0	$ 346.8	$ 215.5	$ 115.3	$ 20.6	$ 4.2	$ 36.6	$ 211.7	$ 70.9	$ 60.1	$ 1,203.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 25.3	$ 1,869.5	$ 1,952.0	$ 8,756.6	$ 5,416.2	$ 2,574.8	$ 600.0	$ 110.8	$ 1,036.1	$ 7,871.3	$ 2,765.1	$ 2,700.8	$ 35,678.3
Net Power Supply Expenses ($ x 1000)	$ 19,487.8	$ 11,300.2	$ 10,504.9	$ (1,282.6)	$ 986.4	$ 6,231.2	$ 19,736.2	$ 28,967.9	$ 17,754.0	$ 9,627.0	$ 15,710.1	$ 17,812.1	$ 156,835.2

IPCO POWER SUPPLY COSTS FOR 2011 NORMALIZED LOADS OVER 83 WATER YEAR CONDITIONS

2010

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	667,711.5	716,661.3	655,111.0	557,583.9	839,515.2	1,082,186.4	676,286.3	494,278.4	520,865.5	525,205.1	413,155.7	540,011.2	7,688,571.5
Bridger													
Energy (MWh)	476,136.6	430,960.1	430,662.8	304,225.4	286,685.3	233,321.2	448,492.0	472,322.9	414,013.0	444,435.7	455,840.1	483,204.5	4,880,299.6
Cost ($ x 1000)	$ 10,471.1	$ 9,475.8	$ 9,543.6	$ 6,804.9	$ 6,417.8	$ 5,250.6	$ 9,916.2	$ 10,394.5	$ 9,179.9	$ 9,834.8	$ 10,034.2	$ 10,612.9	$ 107,936.5
Boardman													
Energy (MWh)	35,274.2	33,007.7	33,437.8	13,263.6	-	20,942.8	39,298.3	38,762.7	36,205.0	35,819.9	36,605.8	39,742.0	362,359.8
Cost ($ x 1000)	$ 635.0	$ 591.1	$ 606.9	$ 249.0	$ -	$ 390.8	$ 696.7	$ 688.5	$ 646.2	$ 643.4	$ 652.4	$ 703.4	$ 6,503.4
Valmy													
Energy (MWh)	113,951.1	106,037.7	811.7	-	-	-	113,439.2	143,522.9	102,392.4	143,628.2	149,060.1	167,758.5	1,040,601.8
Cost ($ x 1000)	$ 3,892.0	$ 3,615.8	$ 29.4	$ -	$ -	$ -	$ 3,868.2	$ 4,847.7	$ 3,494.4	$ 4,855.6	$ 5,022.2	$ 5,625.9	$ 35,251.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	1,362.0	5,217.3	19.8	-	-	-	6,599.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 66.6	$ 261.9	$ 1.0	$ -	$ -	$ -	$ 329.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 450.7	$ 450.8	$ 437.1	$ 451.2	$ 437.5	$ 451.5	$ 5,061.3
Total Cost	$ 345.8	$ 314.5	$ 399.1	$ 436.3	$ 450.3	$ 436.6	$ 517.3	$ 712.7	$ 438.1	$ 451.2	$ 437.5	$ 451.5	$ 5,390.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	193.9	295.6	-	-	-	-	489.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.6	$ 15.0	$ -	$ -	$ -	$ -	$ 24.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.6	$ 15.0	$ -	$ -	$ -	$ -	$ 24.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	12,696.9	10.7	12,919.2	73,799.7	52,505.1	21,712.5	252,262.7	240,049.5	113,010.4	2,311.3	8,918.4	30,118.1	820,314.5
Contract Energy (MWh)	33,741.7	29,559.2	28,374.5	30,179.5	29,292.1	62,289.3	62,432.8	62,205.9	25,333.5	30,470.2	33,945.6	39,085.4	466,909.7
Total Energy Excl. CSPP (MWh)	46,438.6	29,570.0	41,293.7	103,979.2	81,797.3	84,001.7	314,695.5	302,255.3	138,343.9	32,781.5	42,864.0	69,203.5	1,287,224.2
Market Cost ($ x 1000)	$ 372.7	$ 0.3	$ 351.3	$ 2,045.0	$ 1,618.7	$ 538.0	$ 10,124.5	$ 10,368.7	$ 4,534.5	$ 64.5	$ 342.2	$ 1,335.7	$ 31,696.1
Contract Cost ($ x 1000)	$ 1,842.9	$ 1,615.9	$ 1,142.4	$ 1,211.1	$ 1,178.0	$ 4,655.5	$ 4,981.5	$ 5,003.7	$ 1,386.5	$ 1,666.1	$ 2,225.2	$ 2,559.5	$ 29,468.2
Total Cost Excl. CSPP ($ x 1000)	$ 2,215.5	$ 1,616.2	$ 1,493.7	$ 3,256.1	$ 2,796.6	$ 5,193.4	$ 15,106.0	$ 15,372.4	$ 5,921.0	$ 1,730.6	$ 2,567.4	$ 3,895.2	$ 61,164.2
Surplus Sales													
Energy (MWh)	91,241.2	263,377.5	133,034.8	52,841.9	75,564.4	173,609.1	2,330.1	11,430.1	54,643.4	190,856.2	55,357.7	39,124.6	1,143,411.0
Revenue Including Transmission Costs ($ x 1000)	$ 3,524.6	$ 9,514.6	$ 4,095.5	$ 1,570.4	$ 2,033.6	$ 3,904.4	$ 64.9	$ 336.8	$ 1,716.7	$ 7,629.6	$ 2,349.1	$ 1,965.0	$ 38,705.2
Transmission Costs ($ x 1000)	$ 91.2	$ 263.4	$ 133.0	$ 52.8	$ 75.6	$ 173.6	$ 2.3	$ 11.4	$ 54.6	$ 190.9	$ 55.4	$ 39.1	$ 1,143.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,433.4	$ 9,251.3	$ 3,962.5	$ 1,517.6	$ 1,958.0	$ 3,730.8	$ 62.6	$ 325.4	$ 1,662.1	$ 7,438.8	$ 2,293.7	$ 1,925.9	$ 37,561.8
Net Power Supply Expenses ($ x 1000)	$ 14,126.0	$ 6,362.1	$ 8,110.2	$ 9,228.7	$ 7,706.7	$ 7,540.7	$ 30,051.4	$ 31,705.5	$ 18,017.7	$ 10,076.8	$ 16,419.9	$ 19,363.1	$ 178,708.8

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott Wright
2011 October Update

July 29, 2011

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2011 -- MARCH 31, 2012 (Mulitple Gas Prices/82 Years of Hydro)
Repriced Using UE195 Settlement Methodology - October Update
AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	869,315.9	934,395.3	927,661.5	668,304.3	556,415.3	554,533.6	524,903.4	457,406.2	680,120.0	801,632.9	846,805.1	865,084.8	8,686,578.4
Bridger													
Energy (MWh)	271,978.0	224,814.5	235,566.8	429,630.4	450,768.8	411,511.8	442,774.2	444,821.2	475,034.0	383,892.6	341,865.0	332,112.9	4,444,770.2
Cost ($ x 1000)	$ 6,115.4	$ 5,068.7	$ 5,326.6	$ 9,573.8	$ 10,019.6	$ 9,183.0	$ 9,859.5	$ 9,874.2	$ 10,515.5	$ 8,619.3	$ 7,673.1	$ 7,443.3	$ 99,271.8
Boardman													
Energy (MWh)	13,427.4	1,599.6	21,453.9	37,467.2	37,645.9	35,408.3	35,446.7	34,616.5	37,720.0	29,610.6	28,402.5	30,771.8	343,570.4
Cost ($ x 1000)	$ 248.8	$ 30.0	$ 401.6	$ 666.4	$ 669.4	$ 632.1	$ 635.5	$ 619.9	$ 670.5	$ 613.1	$ 586.1	$ 633.1	$ 6,406.6
Valmy													
Energy (MWh)	62,641.5	51,738.0	51,130.7	157,499.6	168,326.2	159,412.3	163,982.9	161,565.3	171,052.4	135,258.3	113,360.1	105,232.7	1,501,200.0
Cost ($ x 1000)	$ 1,823.7	$ 1,517.2	$ 1,500.8	$ 4,526.6	$ 4,831.9	$ 4,584.6	$ 4,725.3	$ 4,645.5	$ 4,903.8	$ 4,058.5	$ 3,401.7	$ 3,156.7	$ 43,676.3
Danskin													
Energy (MWh)	-	-	33.8	2,240.2	2,417.5	442.2	0.2	-	-	-	-	-	5,133.9
Cost ($ x 1000)	$ -	$ -	$ 2.0	$ 135.5	$ 146.4	$ 28.1	$ 0.0	$ -	$ -	$ -	$ -	$ -	$ 311.9
Fixed Capacity Charge - Gas Transportation ($ x 1000	$ 402.1	$ 413.2	$ 400.6	$ 413.2	$ 413.2	$ 400.6	$ 413.2	$ 400.6	$ 413.2	$ 311.0	$ 283.1	$ 364.0	$ 4,628.2
Total Cost	$ 402.1	$ 413.2	$ 402.5	$ 548.7	$ 559.6	$ 428.7	$ 413.2	$ 400.6	$ 413.2	$ 311.0	$ 283.1	$ 364.0	$ 4,940.1
Bennett Mountain													
Energy (MWh)	-	-	5.6	168.9	107.1	15.8	-	-	-	-	-	-	297.5
Cost ($ x 1000)	$ -	$ -	$ 0.3	$ 10.4	$ 6.7	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ 18.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	5,763.6	31,305.3	93,686.7	255,926.2	238,883.0	96,514.6	2,586.9	7,392.1	48,034.8	48,940.5	8,274.1	3,356.7	840,664.6
Contract Energy (MWh)	27,086.1	30,806.6	63,919.2	66,356.3	62,557.4	22,010.0	31,184.2	29,743.0	36,917.3	30,054.1	25,920.7	25,715.8	452,270.8
Total Energy Excl. CSPP (MWh)	32,849.7	62,111.9	157,605.9	322,282.5	301,440.5	118,524.5	33,771.1	37,135.1	84,952.2	78,994.5	34,194.8	29,072.6	1,292,935.4
Market Cost ($ x 1000)	$ 222.1	$ 1,040.0	$ 2,881.6	$ 12,653.7	$ 13,243.5	$ 5,282.4	$ 135.6	$ 404.1	$ 2,831.8	$ 2,796.1	$ 449.8	$ 166.5	$ 42,107.1
Contract Cost ($ x 1000)	$ 1,092.0	$ 1,240.8	$ 4,746.9	$ 5,236.4	$ 5,029.8	$ 1,212.0	$ 1,708.9	$ 1,956.8	$ 2,423.3	$ 1,685.0	$ 1,456.6	$ 1,065.1	$ 28,853.6
Total Cost Excl. CSPP ($ x 1000)	$ 1,314.1	$ 2,280.9	$ 7,628.5	$ 17,890.1	$ 18,273.3	$ 6,494.4	$ 1,844.5	$ 2,360.8	$ 5,255.1	$ 4,481.0	$ 1,906.4	$ 1,231.6	$ 70,960.7
Surplus Sales													
Energy (MWh)	329,683.7	178,759.0	89,821.3	11,778.4	16,554.9	111,506.9	225,068.5	102,062.0	127,723.8	119,562.8	293,787.3	339,098.0	1,945,406.7
Revenue Including Transmission Costs ($ x 1000)	$ 11,519.9	$ 5,384.4	$ 2,504.5	$ 528.0	$ 832.2	$ 5,534.4	$ 10,698.1	$ 5,059.5	$ 6,828.6	$ 6,194.8	$ 14,482.9	$ 15,254.7	$ 84,822.2
Transmission Costs ($ x 1000)	$ 329.7	$ 178.8	$ 89.8	$ 11.8	$ 16.6	$ 111.5	$ 225.1	$ 102.1	$ 127.7	$ 119.6	$ 293.8	$ 339.1	$ 1,945.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 11,190.3	$ 5,205.7	$ 2,414.7	$ 516.2	$ 815.6	$ 5,422.9	$ 10,473.1	$ 4,957.5	$ 6,700.9	$ 6,075.3	$ 14,189.1	$ 14,915.6	$ 82,876.8
Hoku First Block Revenues	$ 2,277.5	$ 2,353.4	$ 1,498.3	$ 743.2	$ 1,238.6	$ 1,977.8	$ 2,353.4	$ 2,277.5	$ 2,353.4	$ 2,353.4	$ 2,201.6	$ 2,353.4	$ 23,981.4
Net Hedges													
Energy (MWh)													
Cost($ X 1000)													
Net Power Supply Costs ($ x 1000)	$ (3,563.6)	$ 1,751.0	$ 11,347.4	$ 31,956.6	$ 32,306.2	$ 13,923.1	$ 4,651.6	$ 10,666.0	$ 12,703.8	$ 9,654.3	$ (2,540.3)	$ (4,440.2)	**$ 118,415.8**
PURPA ($ x 1000)	$ 9,644.1	$ 12,167.0	$ 13,993.0	$ 14,311.8	$ 13,378.7	$ 11,978.7	$ 10,140.6	$ 9,123.2	$ 9,393.8	$ 8,333.2	$ 8,387.4	$ 8,199.6	$ 129,051.2
Total Net Power Supply Expense ($ x 1000)	$ 6,080.5	$ 13,918.0	$ 25,340.4	$ 46,268.4	$ 45,684.8	$ 25,901.8	$ 14,792.1	$ 19,789.2	$ 22,097.6	$ 17,987.6	$ 5,847.1	$ 3,759.4	**$ 247,467.0**
Sales at Customer Level (In 000s MWH)	1,040.305	1,040.308	1,210.219	1,445.744	1,515.844	1,398.071	1,134.719	1,043.802	1,176.700	1,287.009	1,200.626	1,097.626	14,590.974
Hours in Month	720	744	720	744	744	720	744	720	744	744	696	744	8784
Unit Cost / MWH (for PCAM)	$5.84	$13.38	$20.94	$32.00	$30.14	$18.53	$13.04	$18.96	$18.78	$13.98	$4.87	$3.42	**$16.96**
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL F	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
Purchased Power HL Price	41.55	37.70	35.96	55.97	61.16	58.44	54.45	57.03	61.87	59.84	57.19	52.06	
Portion of Surplus Sales considered HL Surp	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
Surplus Sales HL Price	38.56	34.98	33.36	51.93	56.74	54.23	50.52	52.92	57.41	55.52	53.07	48.30	
Light Load													
Portion of Purchased Power considered LL F	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
Purchased Power LL Price	33.10	25.18	21.41	37.71	45.16	48.06	48.75	50.40	53.71	52.26	49.26	45.20	
Portion of Surplus Sales considered LL Surp	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
Surplus Sales LL Price	28.87	21.96	18.67	32.89	39.38	41.91	42.51	43.95	46.84	45.58	42.96	39.42	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF OREGON.	)))))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

July 29, 2011

Q. Please state your name and business address.

A. My name is Timothy E. Tatum 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 ("Idaho Power" or "Company") as the Senior Manager of Cost of Service in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I have earned a Bachelor of Business Administration degree in Economics and Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electrical Industry," a course offered through New Mexico State University's Center for Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course."

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 as a Customer Service Representative in the Company's Customer Service Center where I handled customer phone calls and other customer-related transactions. In 1999, I began working in the Customer Account Management Center where I was responsible for customer account maintenance in the area of billing and metering.

In June of 2003, after seven years in customer service, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I was responsible for ensuring that the Demand-Side Management ("DSM") expenditures were accounted for properly, preparing and reporting DSM program costs and activities to management and various external stakeholders, conducting cost-benefit analyses of DSM programs, and providing DSM analysis support for the Company's 2004 Integrated Resource Plan ("IRP").

In August of 2004, I accepted a position as a Regulatory Analyst in Regulatory Affairs. As a Regulatory Analyst, I provided 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.

In August of 2006, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities expanded to include the development of complex financial studies to determine revenue recovery and pricing strategies, including the preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to Manager of Cost of Service and in April of 2011, I was promoted to Senior Manager of Cost of Service. As Senior Manager of Cost of Service, I oversee the Company's cost-of-service activities such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

I. OVERVIEW

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

A. The purpose of my testimony is to present the forecast methodologies that were applied to the Company's 2010 financial data to arrive at the 2011 forecasted financial levels. Further, my testimony will describe the instructions that I provided to Mr. Scott Wright, Mr. Matthew T. Larkin, and Ms. Kelley Noe with regard to the normalizing, annualizing, and other regulatory adjustments required to arrive at the 2011 test year revenue requirement.

Q. Did you consult with Mr. Gregory W. Said, Vice President of Regulatory Affairs, regarding the development of the 2011 Test Year ("2011 Test Year" or "Test Year")?

A. Yes. The 2011 Test Year development methodology presented in the remainder of my testimony is a direct result of numerous discussions with Mr. Said.

Q. Did Mr. Said provide you with any specific instructions or guidance regarding the development of the Test Year presented in this proceeding?

A. Yes. Mr. Said instructed me to develop the 2011 Test Year based upon 2010 actual financial data in a manner similar to that approved by the Oregon Public Utility Commission ("Commission") in the Company's last general rate case, UE 213 ("2009 Rate Case"). However, Mr. Said instructed me to depart from the methodology used in the 2009 Rate Case in a number of specific areas. First, Mr. Said instructed me to hold operations and maintenance ("O&M") expenses to 2010 levels with the exception of specific cost categories that are "known" to be materially different in 2011. Second, Mr. Said instructed me to hold normalized total power supply expenses to the currently approved (UE 222, Order No. 11-178) normalized levels determined under the October Update component of the 2011 Annual Power Cost Update ("APCU"). Mr. Said's instructions to depart from the methodology used in the 2009 Rate Case have the effect of reducing the Company's revenue requirement request in this case.

Q. Will you briefly summarize how the Company has developed its 2011 Test Year?

A. Yes. The development of the 2011 Test Year began with 2010 actual financial data ("2010 Actuals"). 2010 Actuals were adjusted by Mr. Douglas N. Jones to reflect traditional ratemaking adjustments and to arrive at 2010 adjusted actual financial information ("2010 Base"). The 2010 Base was then adjusted to reach 2011 forecasted financial levels ("2011 Unadjusted Test Year"). Finally, annualizing adjustments were made to the 2011 Unadjusted Test Year to reach the Company's 2011 Test Year.

II. DEVELOPMENT OF THE 2011 UNADJUSTED TEST YEAR

Q. Please describe the forecast methodologies used to adjust the 2010 Base to the 2011 Unadjusted Test Year.

A. There were two primary methods developed and applied to the 2010 Base Year to forecast the 2011 Unadjusted Test Year. First, the Company used the unchanged 2010 Base level financial data when the Company believed that certain amounts would continue to remain at 2010 levels or if account balances were very small. Alternatively, "Other Adjustments" were applied based upon known or probable factors for 2011 that relate to a particular account. Examples of these factors include, but are not limited to, new billing and volume contract terms, discontinued services, anticipated levels of economic activity, and applicable regulatory commission orders.

Q. How does the forecast methodology used in this case differ from that applied in the 2009 Rate Case?

A. Aside from the specific adjustments requested by Mr. Said mentioned earlier in my testimony, the major difference between the forecasting methodology used in this case and that applied in the 2009 Rate Case is the utilization of growth rates to escalate O&M expenses. In the 2009 Rate Case, the Company applied Compound Annual Growth Rates ("CAGRs") to adjust a number of O&M expense accounts. Based on historical data, CAGRs represented a steady level of positive or negative growth from the beginning period to the ending period. To develop the 2011 Test Year, the Company has not applied any escalation factors to forecast O&M expenses. Instead the Company has made a conscious choice to hold test year O&M expenses to 2010 Base levels with adjustments only to specific cost categories that are "known" to be materially different in 2011.

Q. Have you prepared exhibits that list all accounts and identify the specific method you used to forecast the 2011 Unadjusted Test Year?

A. Yes. I directed the preparation of Exhibit 801 to present a summarized list of all accounts to which the two previously discussed methods were applied. Each of the methodologies is described in more detail within the Forecast Methodology Manual, Exhibit 802, which was also prepared at my direction. To develop the Forecast Methodology Manual, the Company performed a review of each group of accounts included within the test year. Based upon specific knowledge and analysis of that account grouping, the Company either used 2010 Actuals or applied an Other Adjustment methodology to that account to represent an appropriate level of anticipated spending.

Q. Have the data and the associated adjustments made to your exhibits and supporting schedules been calculated on a total system basis?

A. Yes. Ms. Noe will address the determination of the Oregon jurisdictional test year values in her testimony.

Q. Please identify the major areas or groupings of financial accounts addressed by the methodologies included in the Forecast Methodology Manual (Exhibit 802).

A. The major areas or groupings of financial accounts addressed in Exhibit 802 include Other Operating Revenues (Accounts 451, 454, and 456), Operation and Maintenance Expenses (Accounts 500 through 900), Depreciation and Amortization Expense (Accounts 403 and 404), and Electric Plant in Service (“EPIS”) (Account 101). A detailed discussion of the individual accounts and methods used is provided in Exhibit 802.

Q. Please provide an overview of the methodology used to forecast 2011 Other Operating Revenues (Accounts 447, 451, 454, and 456).

A. Consistent with Mr. Said's directive, Surplus Sales Revenues (Account 447) were held to the currently approved 2011 normalized levels. The remaining Other Operating Revenues (Accounts 451, 454, and 456) were forecasted to be the same as 2010 actual revenue with the exception of four revenue categories: 1) cogeneration and small power production revenues, 2) facilities charge revenues, 3) network services and other long term firm and point-to-point transmission revenues, and 4) Sierra Pacific Power Company sales.

Cogeneration and small power production revenues were determined by adjusting the 2010 revenues to account for 13 new wind projects that have or will come on-line in 2011. Facilities charge revenues were determined by adjusting the 2010 actual revenues to account for a reduced facilities charge rate as proposed by Mr. Scott D. Sparks in his testimony in this case. Network services and other long-term firm and point-to-point transmission revenues were projected based upon information more reflective of current circumstances and an anticipated Open Access Transmission Tariff rate update in October 2011. Finally, Sierra Pacific Power usage revenues were adjusted to zero to recognize that no usage revenues from Sierra Pacific Power are expected in 2011.

A detailed discussion of the methods applied to determine Other Operating Revenues for the 2011 Unadjusted Test Year is provided on pages 8-10 of Exhibit 802.

Q. Please provide an overview of the methodology used to forecast 2011 Operation and Maintenance Expenses (Accounts 500 through 900).

A. Based upon the instructions I received from Mr. Said, the power supply expense accounts were held to the currently approved 2011 normalized levels. The power supply expense accounts include Fuel Expense (Accounts 501 and 547) and

Purchased Power Expense (Account 555 - excluding purchased power for transmission losses).

The remaining O&M adjustments were also made in accordance with Mr. Said's instructions. The Oregon Energy Efficiency Rider Expense (Account 908) was removed in its entirety from the 2011 Test Year. Incentive Expense (Account 920) was forecasted for 2011 to include only the normalized incentive components that are attributable to Customer Satisfaction and Reliability, consistent with the method filed in the 2009 Rate Case. Incentive expense represents the "at-risk" portion of employees' total compensation package. Pension Expense (Account 926) for the Oregon jurisdiction was determined by the Company's actuary, Milliman, Inc., and represents an estimate of the total 2011 net periodic pension expense under SFAS 87. Regulatory Commission Expenses (Account 928) were adjusted to include known changes in amortizations for recovery of Commission-ordered intervenor funding. The remaining O&M expense amounts were segregated into labor and non-labor expense groupings to determine the respective 2011 forecast amounts.

Q. Did the Company utilize the Oregon Commission Staff's ("Staff") preferred three-year wage and salary analysis to determine the 2011 Test Year O&M labor expense? If not, please explain why it was not used.

A. No. In prior general rate case proceedings the Staff has indicated its preference for a three-year wage and salary analysis to determine test year O&M labor expense. The Staff's wage and salary analysis utilizes the Consumer Price Index ("CPI") as a basis to escalate wages from a base year, typically three years prior to the requested test period in a rate case. Further, it is the Company's understanding that the Staff's analysis is intended to be applied to non-union positions or positions that are not subject to contract-driven wage adjustments.

The Company does not believe the Staff's wage and salary analysis is appropriately applied to Idaho Power for a number of reasons. First, the Company does not believe that CPI is representative of the primary factors that drive wage increases. Further, CPI does not recognize that employees' wages are driven by factors other than inflation. Wage levels are also impacted as employees move through the salary structure for reasons such as promotions and/or merit salary increases. Second, the Staff's wage analysis arbitrarily selects a base year upon which to apply the CPI factors. Even if the escalation factors applied under this approach were reflective of the true factors that drive wages, which CPI is not, applying them to a base year that is not representative of a normal operating year could yield unreasonable results. Third, the Staff's wage analysis does not recognize that although Idaho Power is a non-union shop, the Company endeavors to maintain wages at market competitive levels for job classifications in which it competes with other union companies in the region for employees.

Q. Please provide an overview of the methodology used to forecast 2011 O&M labor expense.

A. The 2011 labor expense was forecasted by applying historical monthly labor cost relationships to the first two calendar months of 2011 actual labor costs. More specifically, the 2011 O&M labor forecast was developed by first calculating the three-year historical average of February year-to-date actual O&M labor costs as a percentage of the total year actual O&M labor costs. The resulting percentage was determined to be 15.00 percent. This percentage was then applied to the actual February 2011 year-to-date O&M labor to estimate the total 2011 O&M labor costs. The February amount was first reduced by pension expense and by the Smart Grid related O&M labor, which has a credit offset in a non-labor cost element. The resulting 2011 labor projection of $133.9 million was then allocated to the applicable

Federal Energy Regulatory Commission ("FERC") accounts based on 2010 actual labor charges to those same accounts. A more detailed discussion of the labor-related O&M adjustment is provided in Exhibit 802, pages 10 and 11.

Q. Please provide an overview of the forecast methodology used to forecast 2011 non-labor O&M expenses.

A. The 2011 non-labor O&M expenses, excluding the accounts mentioned above, were projected to be equal to the 2010 actual expense level with adjustments only for significant known changes. At my direction, the O&M expenses were reviewed by subject matter experts to identify and adjust those areas, based on specific knowledge, where expense levels are expected to be materially different than those included in the 2010 Base. The review identified significant specific increases or decreases to the 2010 non-labor actual levels in the following categories:

- Thermal O&M Increases Identified by Operating Partners
- Bennett Mountain - Combustor Inspection
- Commission-Ordered Amortizations
- Smart Grid Investment Grant Credit in 2010 - Not Recurring
- Light Data and Ranging Surveys to meet North American Electric Reliability Corporation Requirements
- Bureau of Land Management Rate Increase - Land Rents
- Idaho Fish and Game's Projected Hatchery Expense Increases
- Increased IT Maintenance Expenses
- Specific Reliability Projects - Transmission

Actual 2010 non-labor O&M, excluding the items identified previously, equaled $142.3 million. Following the adjustments for significant known changes, non-labor O&M is projected to increase by $15.6 million to $157.9 million. A more detailed discussion of the non-labor O&M adjustments is provided in Exhibit 802, pages 11-15.

Q. Please provide an overview of the methodology to forecast 2011 Depreciation and Amortization Expense (Accounts 403 and 404).

A. The 2011 depreciation expense, amortization expense, and related reserve accounts were calculated based on the monthly estimated 2011 plant balances. Depreciation rates authorized by Commission Order No. 09-317 (Docket No. UM 1395) were used for the entire 2011 Test Year. The determination of the Depreciation and Amortization Expense adjustments is detailed in Exhibit 802, pages 22-23.

Q. Please provide an overview of the methodology to forecast 2011 Electric Plant in Service (Account 101).

A. Electric Plant in Service is a function of multiple components, including actual year-end 2010 EPIS and Construction Work in Progress ("CWIP") balances, estimated 2011 spending, expected 2011 closings of CWIP, and estimated retirements. Therefore, it was necessary to use a number of methodologies to develop the 2011 Unadjusted Test Year EPIS balances, which are detailed in Exhibit 802, pages 27-28.

To project 2011 construction expenditures and 2011 closings of CWIP to EPIS, at Mr. Said's instruction, the Company first bifurcated into two separate and distinct parts, those projects in excess of $2 million and those under $2 million.

Projects in excess of $2 million were reviewed by the individual project managers, who estimated the costs to complete and the in-service date of each project. The investment in projects under $2 million (excluding vehicles) closing to EPIS as a group, was forecasted to be comparable to actual 2010 closings to EPIS when determining the 2011 Unadjusted Test Year. This method is based upon an assumption that construction activities in 2011 are not anticipated to exceed, but rather keep pace with, 2010 levels.

III. ANNUALIZING & OTHER ADJUSTMENTS TO ARRIVE AT THE 2011 TEST YEAR

Q. In Mr. Jones's testimony, he describes the various adjustments that were made to 2010 Actuals to arrive at the 2011 Base Year. Do these same adjustments need to be made in 2011?

A. No. These adjustments are standard ratemaking adjustments based on prior Commission orders and are adjustments to charges included in the 2010 Actuals. By removing them from 2010 Actuals prior to applying the various methodologies to arrive at the Company's proposed 2011 Unadjusted Test Year, the same adjustments are already accounted for.

Q. What were your instructions to Mr. Wright with regard to the Company's determination of the Test Year normalized net power supply expenses?

A. As mentioned earlier in my testimony, Mr. Said directed me to hold the power supply expense accounts to the currently approved 2011 normalized levels (Order No. 11-178). However, I instructed Mr. Wright to update the Company's normalized net power supply expenses for the 2011 test year for informational purposes. Based on Mr. Wright's analysis, the updated 2011 test year net power supply expenses, including PURPA, would be $267.5 million, an increase of $20.0 million over the currently approved 2011 net power supply expenses, including PURPA, of $247.5 million. Even though Mr. Wright's analysis would suggest a need to increase the level of net power supply expense recovery through base rates, the Company believes that this matter is appropriately addressed in the context of the annual October Update component of the APCU. Mr. Wright provides a detailed discussion of his analysis in his direct testimony.

Q. What were your instructions to Mr. Larkin with regard to the determination of the Test Year retail sales revenues (Account 442)?

A. I instructed Mr. Larkin to determine the 2011 Test Year retail sales revenues using the same methodology used in the 2009 Rate Case. That is, my instructions were to develop the Test Year retail sales revenues based upon forecasted billing determinants under normal weather and precipitation assumptions. As Mr. Larkin will cover in greater detail in his testimony, the 2011 Test Year billing determinants were developed based upon the Company's energy sales and customer count forecasts prepared for the 2011 IRP. To derive the demand-related billing determinants, historical demand-to-energy relationships were applied to the energy sales forecast. The forecasted billing determinants were then applied to the rates in effect at the time of the filing to determine the 2011 Test Year retail sales revenues.

Q. Are there any additional adjustments that need to be made to properly reflect the 2011 Test Year?

A. Yes. It is necessary for the Company to make additional annualizing and known and measureable adjustments.

Q. Please describe the additional annualizing adjustments made under your direction to the 2011 Test Year.

A. I instructed Ms. Noe to make annualizing adjustments to certain expense and rate base items to reflect them as though they have been in existence for the entire Test Year; that is, at year-end 2011 levels. These include operating payroll, 2012 salary structure adjustment, depreciation expense and reserve, and plant placed in service during 2011 in excess of $2 million with the associated estimated property taxes and insurance premiums. Such adjustments are appropriate to reflect conditions that will be in effect at the time rates are placed in effect. Ms. Noe provides additional detail regarding the annualizing adjustments in her testimony.

Q. Did you have any additional instructions for Ms. Noe?

A. Yes. Consistent with Mr. Said's directive, I instructed Ms. Noe to use the Commission-approved 2011 normalized power supply expenses in the Oregon jurisdictional revenue requirement determination.

Q. Has an exhibit been prepared that details each of the adjustments that were made to move from the 2010 Actuals to the 2011 Test Year?

A. Yes. Ms. Noe's Exhibit 904 summarizes the adjustments that were made to each FERC Account to: 1) move from the 2010 Actuals to the 2010 Base, 2) move from the 2010 Base to the 2011 Unadjusted Test Year, and 3) move from the 2011 Unadjusted Test Year to the 2011 Test Year.

Q. According to Ms. Noe's analysis using the 2011 Test Year financial information, what is the Company's revenue requirement on a system-wide and Oregon jurisdictional basis?

A. Using the 2011 Test Year financial information, Ms. Noe has calculated the Company's revenue requirement to be $981.6 million on a system-wide basis and $45.7 million on an Oregon jurisdictional basis. Ms. Noe calculated the Company's annual revenue deficiency, the amount that the Test Year revenue requirement exceeds the Test Year retail sales revenue, to be $105.6 million on a system-wide basis, and $5.8 million on an Oregon jurisdictional basis. An increase to annual Oregon jurisdictional revenues in the amount of $5.8 million would result in an overall average increase to customer rates of 14.7 percent.

Q. Is it appropriate for the Commission to determine the Company's Oregon jurisdictional revenue requirement to be $45.7 million, its revenue deficiency to be $5.8 million, and therefore, approve an overall 14.7 percent increase to customer rates?

A. Yes. The $45.7 million figure is a reasonable determination of the Company's annual Oregon jurisdictional revenue requirement. The $5.8 million quantification of revenue deficiency is also reasonable. It is in the best interest of the Company and its customers for the Commission to approve a rate increase to provide a 14.7 percent increase to the Company's Oregon jurisdictional revenues.

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

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Timothy E. Tatum
Forecast Methodology Summary

July 29, 2011

IDAHO POWER COMPANY
Methodology Summary
2011 Oregon Test Year

- 2010 Base
- Other Methodology
- Normalized
- Removed in its Entirety

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
	Cost of Service Components		
	Other Operating Revenues		
1	Miscellaneous Service Revenues	451	2010 Base
	Rent from Electric Property		
2	Substation equipment	454	2010 Base
3	Transformer & distribution rentals	454	2010 Base
4	Station and line rentals	454	2010 Base
5	Cogeneration and small power production	454	Other Methodology
6	Real estate rents	454	2010 Base
7	Dark fiber rents	454	2010 Base
8	Joint pole attachments	454	2010 Base
9	Facilities charges	454	Other Methodology
10	Overnight park rents	454	2010 Base
	Other Electric Revenues		
11	Net Work Service and Other Long Term Firm	456	Other Methodology
12	Point-to-Point	456	Other Methodology
13	Photovoltaic	456	2010 Base
14	Antelope	456	2010 Base
15	Sierra Pacific Power Company sales	456	Removed in its entirety
16	Stand-by service	456	2010 Base
17	Energy Efficiency Rider	456	2010 Base
18	Miscellaneous	456	2010 Base
	Other Revenues and Expenses		
	Other Revenues		
19	Power Solutions	415	2010 Base
20	Hydro Services	415	2010 Base
21	Water Management Services	415	2010 Base
22	QRE Reporting	415	2010 Base
23	Joint Use (Pole) - Idaho	415	2010 Base
24	Joint Use (Pole) - Oregon	415	2010 Base
	Other Expenses		
25	Power Solutions	416	2010 Base
26	Hydro Services	416	2010 Base
27	Water Management Services	416	2010 Base
28	QRE Reporting	416	2010 Base
29	Joint Use (Pole) - Idaho	416	2010 Base
30	Joint Use (Pole) - Oregon	416	2010 Base

IDAHO POWER COMPANY
Methodology Summary
2011 Oregon Test Year

- **- 2010 Base**
- **- Other Methodology**
- **- Normalized**
- **- Removed in its Entirety**

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
	Operations and Maintenance Expenses		
	Power production expenses		
31	Steam power generation(excluding account 501)	500-514	Other Methodology
32	Fuel expense	501	Normalized
33	Hydraulic power generation	535-545	Other Methodology
34	Other power generation(excluding 547.1)	546-554	Other Methodology
35	Fuel expense	547	Normalized
	Other power supply expenses		
36	Purchased power (excluding 555.050)	555	Normalized
37	Transmission losses	555.050	Other Methodology
38	System control and load dispatch	556	Other Methodology
39	Other expenses	557.050	Other Methodology
40	Other expenses - PCA, EPC and PCAM (excluding 557.050)	557	Removed in its entirety
41	Transmission expenses	560-573	Other Methodology
42	Distribution expenses	580-598	Other Methodology
43	Customer account, service and information expenses	901-912	Other Methodology
44	Administrative & general expenses(excluding accts 908.1 and 930.1)	920-935	Other Methodology
45	Energy Efficiency Rider expenses	908.1	Removed in its entirety
46	General advertising expenses	930.1	Removed in its entirety
	Depreciation and Amortization Expense		
47	Depreciation	403	Other Methodology
48	Amortization	404	Other Methodology
	Electric Plant/Regulatory Assets - Amort, Adj, Gains & Losses		
49	Amortization of electric plant acquisition adjustment-Prairie Power	406	Other Methodology
50	**Regulatory Debits and Credits**	407.3	Other Methodology
	Taxes Other Than Income		
51	Real and personal property	408.1	Other Methodology
52	Kilowatt-hour tax - Idaho	408.1	Normalized
	Licenses		
53	Wyoming	408.1	Other Methodology
54	Shoshone-Bannock	408.1	Other Methodology
	Regulatory commission		
55	Idaho	408.1	2010 Base
56	Oregon	408.1	Other Methodology
57	Franchise tax - Oregon	408.1	Other Methodology
58	**Idaho Energy Resources Statement of Income**	418.1/419	Other Methodology

IDAHO POWER COMPANY
Methodology Summary
2011 Oregon Test Year

- **- 2010 Base**
- **- Other Methodology**
- **- Normalized**
- **- Removed in its Entirety**

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
	Rate Base Components		
	Electric Plant-In-Service		
59	Projects > $2 million	101	Other Methodology
60	Projects < $2 million	101	2010 Base
	Accumulated Reserve for Depreciation and Amortization		
61	Depreciation reserve	108	Other Methodology
62	Amortization reserve	111	Other Methodology
	Materials and Supplies		
63	Plant materials and operating supplies	154	Other Methodology
64	Stores expense undistributed	163	Other Methodology
65	**Deferred Conservation Programs**	182.3	Other Methodology
66	**Other Deferred Programs**	182.3/186.722/186.770	Other Methodology
67	**Deferred Income Taxes**	190/282/283	Other Methodology
68	**Customer Advances For Construction**	252	Other Methodology
69	**IERCO-Subsidiary Rate Base Components**	123.1/186/145	Other Methodology

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Timothy E. Tatum
Forecast Methodology Manual

July 29, 2011

Forecast Methodology Manual

Proprietary

2011 Rate Case

TABLE OF CONTENTS

CROSS-REFERENCE LIST OF TABLES

Provided in Ms. Noe's Exhibits

INTRODUCTION

This Forecast Methodology Manual ("Manual") was developed solely to provide supporting information for the methodologies that Idaho Power Company ("IPC") used to set the values contained in its proposed 2011 test year in the 2011 general rate case filing before the Oregon Public Utility Commission ("OPUC"). The financial forecasts, estimates, and other information contained herein were developed solely for ratemaking purposes. This Manual should not be relied upon by current or prospective investors or securities market professionals for any purpose.

The values described in this Manual were provided to IPC witness Noe for appropriate application to the Uniform System of Accounts for determination of revenue requirement in the 2011 test year. The manual is organized in three sections and includes:

- **Forecast Methods.** Forecast Methods includes a description of the forecast methodologies used to develop the 2011 unadjusted test year from the 2010 actual financial data.

- **Cost of Service Components.** Cost of Service Components includes a description of the three digit account number specified in the Uniform System of Accounts adopted by the Commission and the FERC and the forecast method for each major account or account group.

- **Rate Base Components.** Rate Base Components includes a description of the three digit account number specified in the Uniform System of Accounts adopted by the Commission and the FERC and the forecast method applied for each major account or account group.

FORECAST METHODS

Updates to the 2010 actual financial data to IPC's proposed 2011 unadjusted test year were developed using one of the following two forecast methods:

(1) **2010 Base.** 2010 actual financial data was used when the IPC believed that certain amounts would continue to remain at 2010 levels or if account balances were very small.

(2) **Other Adjustments.** Other Adjustments are based on known or probable factors for 2011 that relate to a particular account. Examples of these factors include but are not limited to new billing and volume contract terms, discontinued services, anticipated levels of economic activity, and existing regulatory commission orders.

COST OF SERVICE COMPONENTS

Forecast Adjustment A—Other Operating Revenues

Table 4—FERC Accounts 451–456

Description

Account 451 includes revenues for all miscellaneous services and charges billed to customers that are not specifically provided for in other accounts. This includes fees for changing, connecting, or disconnecting services and profit on maintenance or installations on customers' premises. Miscellaneous service revenues include continuous service reversion charges (Idaho only), field visit charges, return trip charges, returned check fees, service connection charges, service establishment charges, and application and processing fees collected for new permits, new leases, or requests for easement relinquishments. Account 454 includes rents received for the use by others of land, buildings, and other property devoted to electric operations by IPC such as joint pole attachments, facilities charges, and line and substation rents. Account 456 includes revenues derived from electric operations not includable in other revenue accounts. For example, compensation for minor services provided for others, such as engineering and revenues from transmission of electricity of others over transmission facilities of IPC, such as network and point-to-point wheeling.

Forecast Methodology

Forecast Adjustment A increases Other Operating Revenue (Accounts 451–456) by $1,577,758 above the 2010 Base. Accounts 451 through 456 used a combination of the methods for projecting 2011 amounts as described below.

Account 451—Miscellaneous Service Revenues. These revenues were projected for 2011 to be the same as the 12 months actual ended December 2010 Base. This method was used because revenues in this category are not expected to either decrease or increase materially beyond the 2010 level.

Account 454—Rent from Electric Property. Rents from Electric Property were projected based on either the twelve months actual ended December 2010 balance or the Other Adjustment methodology.

Substation equipment rentals, transformer and distribution rentals, station and line rentals, real estate rents, dark fiber rents, joint pole attachments, overnight park rents were forecasted to be the same as the 2010 Base, as this was the most reasonable expectation for these revenues.

Cogeneration and small power production revenues and facilities charge revenues were determined by using the Other Adjustment methodology. The 2010 Base was increased for thirteen new wind projects that have or will come on-line in 2011. For 2011, cogeneration and small power production revenues were calculated by taking the number of identified wind projects times the historical average annual revenue per wind project and then increased by an annual historical growth rate of 4.5%. All existing cogeneration and small power production revenues (Schedule 72 only) were also increased by 4.5% for annual historical growth. This resulted in a forecast adjustment for $197,439 for cogeneration and small power production revenues. For facilities charge revenues, IPC reviews the rate for these charges intermittently. During a recent review, IPC determined that the rate should be decreased based on the current methodology. For 2011, the new annual rate will decrease the revenues generated from the facilities charges by $1,214,026.

Account 456—Other Electric Revenues. Other Electric Revenues were projected based using either the carry-forward of the 2010 Base or the Other Adjustment methodology based on known factors of the individual type of 2011 revenues to be projected as described below:

Revenues related to the photovoltaic station service, Antelope substation, Sierra stand-by service, and miscellaneous were projected for 2011 to be the same as the 2010 Base, as this was the most reasonable expectation for these revenues.

The 2011 Network Transmission Customer revenues were calculated based on nine months of the network transmission customers' average load ratio share times the formula-based FERC transmission revenue requirement in effect from October 1, 2010, through September 30, 2011, and three months of the network transmission customers' average load ratio share times the forecasted FERC transmission revenue requirement. The timing for the Transmission Revenue Requirement is the same as the point-to-point wheeling rate described below. The 2011 estimated network customer MW demand used to calculate the Network Transmission Customer revenue was calculated by taking 2009 MW demand and escalating it using the .7% annual growth factor assumed in the 2009 IRP for 2010. The escalated 2010 MW demand was then increased by 2 MW for new network customer MW demand in 2011

The 2011 point-to-point ("PTP") wheeling revenues were forecasted based on the Other Adjustment methodology and were calculated based on nine months of the 2011 equivalent KWhs times the formula based FERC transmission rate, effective October 1, 2010, through September 30, 2011, and three months of the 2011 equivalent KWhs times the forecasted transmission rate. The three-quarters and one-quarter year revenue calculation split uses the known current transmission rate is in effect through September 30, 2011, and forecasting a rate that would be in effect October 1, 2011 for the final three months. The 2011 equivalent KWhs are based on an average of 2009 and 2010 equivalent KWhs.

Sierra Pacific Power Usage revenues were forecasted based on the Other Adjustment methodology. For 2011, Valmy usage is not expected to exceed capacity; therefore no revenues from Sierra Pacific Power Usage are expected.

Forecast Adjustment B & C—Other Revenues and Other Expenses

Tables 4&5—FERC Accounts 415–416 (excluding 415.002 and 416.002)

Description

Accounts 415 through 416 respectively, include all revenues derived from the sale of merchandise and jobbing or contract work and all expenses incurred in such activities. For IPC, jobbing and contract work revenues and expenses include activities related to Idaho Power Solutions, water management services, and joint pole use.

Forecast Methodology

Forecast Adjustments B and C for Other Revenues (Account 415) and Other Expenses (Account 416), respectively are both $0, therefore the 2011 forecast remains the same as the 2010 Base.

Actual account 415 and account 416 results have not seen significant growth or decline over the last two years. Revenues and expenses in these accounts are typically close to equal and offsetting. Therefore, any fluctuations in these accounts from year to year have little or no impact on the revenue requirement.

Forecast Adjustment D—Operations and Maintenance Expenses ("O&M")

Table 5—FERC Accounts 500–935

Overview

Forecast Adjustment D increases Operations and Maintenance Expenses ("O&M") (Accounts 500–935) by $41,282,700 above the 2010 Base. Excluded from Adjustment D is any increase in normalized accounts 501—Fuel, 547—Fuel, 555—Purchased Power.

In developing the 2011 forecast, IPC split O&M historical actuals into two elements (Labor and Non-Labor) and forecasted each element separately and then allocated each separately to the individual FERC accounts. Excluded from this process were accounts 555.050 (Purchased Power Transmission Losses), 565.000 (Transmission of Electricity by Others), 908.131, 908.132 (Idaho and Oregon Energy Efficiency Riders), 920.001 (Incentive), 926.203, 926.204, and 926.205 (Pension Expense), and 928.203 and 928.303 (Regulatory Commission Expenses), as these were handled separately

Labor

IPC calculated the projected 2011 O&M labor by first calculating the average three-year historical February year-to-date actual O&M labor costs as a percentage of the total year actual O&M labor costs which was determined to be 15.00%. This percentage was then applied to the actual February 2011 year-to-date O&M labor of $20,083,335 to estimate the total 2011 O&M labor costs of $133,886,252 (the February amount was first reduced by pension expense accounts 926.203, 204 and 205), and by the Smart Grid related O&M labor (cost centers 305 and 888) which has a credit offset in a non-labor cost element. The 2011 labor projection was then allocated to FERC account based on 2010 actual labor charges to those same accounts.

The table below details the 2011 estimated labor amount:

2011 Labor Expenses	Total
February Y-T-D O&M Labor Excluding Incentive & Pension	$20,083,335
Divided by the Historical February Y-T-D as a Percentage of Total Year Labor	15.00%
2011 O&M Labor Expense Excluding Incentive and Pension	$133,886,252

Non-Labor

IPC calculated the projected 2011 non-labor O&M expenses by holding to 2010 non-payroll actual expenses with adjustments for significant known changes. IPC reviewed the O&M expenses to identify and adjust those areas, based on specific knowledge, where expected expense levels are expected to be materially different than those included in the 2010 actuals.

The table below identifies significant specific increases or decreases to the 2010 non-labor actual:

2011 O&M Non-Labor Expenses	Total	Allocated	Direct Assignment
2010 O&M Non-Labor Actuals	$142,271,408	$0	$142,271,408
2011 Identified Significant Known Adjustments			
Thermal O&M Increases from Operating Partners	6,708,356	—	6,708,356
Bennett Mountain—2011 Combustor Inspection	1,257,722	—	1,257,722
Commission Ordered Amortizations	(1,466,130)	—	(1,466,130)
Smart Grid Investment Grant (“SGIG”) Credit in 2010 Not Recurring	4,437,427	4,437,427	—
NERC Required LIDAR Surveys	1,414,000	—	1,414,000
BLM Rate Increase—Land Rents	841,224	—	841,224
Idaho Fish and Game’s Projected Hatchery Increases	731,856	—	731,856
Increased IT Maintenance Expenses	723,200	—	723,200
Special Reliability Projects—Transmission	950,000	—	950,000
Inflation and Growth Related Increases	—	—	—
Subtotal 2011 Identified Significant Known Adjustments	15,597,655	4,437,427	11,160,228
Total 2011 O&M Non-Payroll Expenses	**$157,869,063**	**$4,437,427**	**$153,431,636**

The following adjustment to the 2010 Base included in the table above have been allocated to FERC account balances rather than directly assigned:

- **SGIG credit in 2010 not recurring—**O&M work relating to Smart Grid in 2010 was reduced by federal government reimbursements. The positions previously occupied by those involved with SGIG were largely left unfilled when those individuals began working on the Smart Grid project. In the latter part of 2010 and in 2011, those unoccupied positions will or have been filled so the reduction to overall O&M that was generated by the 2010 credit will not reoccur in 2011.

The following adjustments to the 2010 Base included in the table above have been directly assigned to one or more FERC accounts:

- **Power Supply Thermal (Excluding Fuel)—**2010 actual thermal plant O&M was increased by $6,708,356 due to the following:

  - *Valmy Power Plant*—Non-fuel O&M expenses at the Valmy Plant for 2011 is expected to increase by approximately 11% over 2010 levels. The increases are due to rising chemical costs and usage; higher property insurance, legal, and environmental costs; and higher general administrative overheads. These increases are partially offset by lower maintenance costs associated with the major unit outage. Major maintenance is done on each of the two Valmy units every three years. Unit 2 was overhauled in 2010, while unit 1 will be overhauled in 2011. Unit 2 has a scrubber and therefore incurs the majority of the chemical costs at the plant. Chemical expenses were lower in 2010 because this unit was offline for major maintenance for nine weeks. To offset this increase for 2011, overall maintenance expenses in 2011 are expected to be down as the duration of the major unit overhaul on Unit 1 will be shorter and the scope of repair work is expected to be less than Unit 2. Administrative and general overheads are expected to be higher in 2011 due to an increase in plant O&M expenses and retroactive credits recorded in 2010 that will not re-occur in 2011. IPC negotiates an administrative and general ("A&G") rate for Valmy that is applied to actual plant O&M expenses. Periodically Valmy A&G expenses that get allocated to IPC by use of this rate are "trued-up" to actual costs. NV Energy issued IPC credits in 2010 because actual 2009 and a portion of actual 2010 A&G expenses were less than what was charged out through the A&G rate. A fixed Valmy A&G rate was negotiated in 2010 that will carry through mid-year 2012. No prior period true-up credits or charges are expected to occur in 2011.

  - *Bridger Power Plant*—O&M labor costs in 2011 at the Jim Bridger Plant are expected to increase 12.5% compared to 2010 levels. The increase is attributed to PacifiCorp's wage escalation and enhanced 401K benefits per Union Contract Local 127 that was renegotiated in 2010. In addition, a reduction in capital spending at the Jim Bridger plant is expected to result in additional labor dollars being allocated to O&M as compared to 2010.

    O&M expenses attributed to materials are expected to increase 9.4%, compared to 2010 levels. The increase is primarily due to chemicals used to treat mine water being diverted to the plant for use in the cooling towers, as well as additional materials planning to be consumed or installed as part of the maintenance overhaul on Unit #3.

O&M expenses attributed to outside services are expected to increase 22.4%, compared to 2010 levels. A reduction in capital spending at the Jim Bridger plant is expected to result in additional services being allocated to O&M that could not be charged to capital as done in 2010. Examples include boiler scaffolding expenses of approximately $1 million that was charged to the low NO_x burner capital project in 2010, but will be classified as O&M this year and turbine bearing work related to the 2010 turbine upgrade project.

Neither the impairment cost incurred in 2010 related to the delay and likely cancelation of the turbine upgrade projects nor the reduction from a prior year accrual true-up are expected to recur in 2011.

- *Boardman Power Plant*—Non-fuel O&M expenses at the Boardman plant are expected to increase 24% or $840,000 from 2010 levels. The increase is attributed to additional additives and chemicals that will result from the installation of Mercury and NOx retrofits planned to be in-service by mid-2011, as well as an increase in overall plant maintenance. The pollution control retrofits at Boardman in 2011 are being installed to comply with the Oregon Utility Mercury Rule to reduce mercury emissions, and comply with federal regional haze (RH BART) rules for NOx reductions.

  The Boardman plant experienced an outstanding year in 2010, with a forced outage factor (sum of all hours experienced during forced outages divided by number of hours the unit was in an active state) of 2.4% compared to an 2009 forced outage rate of 5.4%. This was due to fewer forced outages, specifically tube leaks, as compared to recent years. This, combined with fewer problems and issues being discovered during the major maintenance outage, caused 2010 overall maintenance expenses to be less than what the plant has experienced in recent years. The increase in plant maintenance expenses expected in 2011 is primarily the result of using historical trending to build the forecast, rather than simply relying on the 2010 result.

  While the increases above were directly assigned to the overall Power Supply Thermal (Excluding Fuel) accounts, these increases were then allocated to FERC accounts 500–515 (excluding 501) based on 2010 actuals amounts in those same accounts.

- **Bennett Mountain Combustor Inspection**—Account 554 was increased by $1,257,722 above 2010 Base due to a scheduled periodic combustor inspection and combustor parts refurbishment at the Bennett Mountain Power Plant. An inspection was not performed in 2010.

- **Commission Ordered Amortizations—The following amortizations resulted in a decrease to the 2010 Base by $1,466,130.**

Account 908 was reduced by $1,621,331 due to the non-recurring DSM/Conservation (Idaho Public Utilities Commission ("IPUC") Order No. 27660) amortization that was completed in June 2010.

Account 928 was increased $155,201 due to 2011 having three fewer months of the credit amortization of the FERC OFA refund (IPUC Order No. 30722 and 30791). This amortization is completed in August 2011.

- **NERC Required LIDAR Surveys**—Account 563 was increased by $1,414,000 due to the need to perform LIDAR Surveys (Light Detection and Ranging) to verify transmission line rating values and methodology in order to satisfy the NERC Alert issued in October 2010.

- **BLM Rate Increase for Land Rents**—Accounts 567, 589, 931 and 935 increased $841,224 over the 2010 Base rents due to new Federal rent schedules and Zone schedule changes. These rents are for IPC lines and facilities that are located on BLM lands. Five FERC accounts were increased based on 2010 actuals as follows—account 935 was increased by $4,070; account 921 was increased by $128,026; account 931 was increased $12,173; account 589 was increased $135,786; and account 567 was increased by $561,169.

- **Idaho Fish & Game's Projected Hatchery Increases**—Account 537 was increased above 2010 Base by $731,856 due to a projected increase from Idaho Department of Fish & Game (IDFG) for hatchery operations. The increase is related to a number of factors including expanded harvest monitoring/hatchery performance evaluation, increased personnel, O&M and overhead costs, development of a fish identification system, and a contribution toward a region-wide hatchery data base.

- **Increased IT Maintenance Expenses**—Account 921 was increased by $723,200 due to software and hardware maintenance increases. SGIG projects hardware and software maintenance (after the product's first year) is not reimbursed by the government. This amount is incremental since IPC will still be operating on the legacy mainframe systems until the new hardware and software is fully tested and promoted into production. The expected in-service date is the second quarter of 2013 for the new applications. At that time, IPC will be archiving data from the legacy systems and beginning the process to discontinue maintenance on these legacy systems. IPC has also included an incremental amount for storage and monitoring tools due to an increase in data storage required on an annual basis and the increase in new open systems that require monitoring tools.

- **Special Reliability Projects**—Transmission, account 563, was increased by $950,000 for transmission projects that are above the normal level of transmission maintenance that was performed in 2010. The projects will repair or replace guy wires on the Bridger to Goshen Transmission Line, and replace dead-ends on the Oxbow to Pallette Junction Transmission Line.

Once O&M labor and non-labor increase or decrease amounts were determined for each FERC account, the results were combined to reflect the total forecast adjustment.

FERC Account Development

Since IPC does not forecast by individual FERC accounts the following two methods (Direct Assignment and Allocation) were used to assign both labor and non-labor to the appropriate FERC accounts.

Direct Assignment Method—The forecast adjustments listed in the direct assignment column in the non-labor expenses above are charges that would occur in specific accounts and therefore were directly assigned to those accounts listed below.

- Account 500–515—Thermal Plant O&M
- Account 537—Idaho Fish & Game’s Projected Hatchery Increases
- Account 554—Bennett Mountain Combustor Inspection
- Account 563—NERC Required LIDAR Surveys; Transmission Reliability Projects
- Account 567—a portion of the BLM Rate Increase
- Account 589—a portion of the BLM Rate Increase
- Account 908—Non-recurring DSM Amortization
- Account 921—IT Maintenance Expenses; a portion of the BLM Rate Increase
- Account 928—Non-recurring Amortization of FERC OFA Refund
- Account 931—a portion of the BLM Rate Increase
- Account 935—a portion of the BLM Rate Increase

Allocation Method—This method was used to allocate the forecast amounts when the identification of specific accounts was impossible or when the impact would be to all accounts. The O&M labor forecast was allocated to individual FERC accounts based on the percentage of 2010 actual O&M labor charges incurred within each account to total O&M labor charges incurred in 2010. The O&M non-labor forecast (not directly assigned) was allocated based on 2010 actual non-labor charges included in each FERC account to total O&M non-labor charges incurred in 2010.

Exceptions to the Described O&M Methodology Above

FERC Accounts 555.050, 565.000, 908.131, 908.132, 920.001, 926.203, 926.204, 926.205, 928.202, 928.203, and 928.303

As stated earlier, the following were forecasted separately from the labor and non-labor O&M forecast described above and directly assigned to the FERC accounts they impact:

- **Account 501—Fuel Expense.** The forecast amount included in this account is the same amount used for the October update of the 2010 Annual Power Cost Update (APCU) docket UE 222.

- **Account 547—Fuel Expense (Excluding 547.000—Salmon Diesel).** The forecast amount included in this account is the same amount used for the October update of the 2010 Annual Power Cost Update (APCU) docket UE 222.

- **Account 555—Purchased Power (Excluding 555.050).** The forecast amount included in this account is the same amount used for the October update of the 2010 Annual Power Cost Update (APCU) docket UE 222.

- **Account 555.050—Purchased Power Transmission Losses.** This account is anticipated to increase above the 2010 Base by $359,462.

- **Account 557—Other Expense (Excluding 557.000).** The amounts in these accounts have been removed in their entirety from the test year.

- **Account 565.000—Transmission of Electricity by Others.** This account is forecasted by combining each individual month's actual expenses for the previous four years and then averaging each month. This average monthly amount is then combined for the twelve months and used as the 2011 forecast.

- **Account 908.131 and 908.132—Idaho and Oregon Energy Efficiency Rider Expenses.** The amounts in these accounts have been removed from the 2010 Base in their entirety per the IPUC Order No. 30189.

- **Account 920.001—Incentive Expense.** The entire actual 2010 incentive expense of $16,398,839 was removed from the 2010 Base and replaced with the projected 2011 incentive of $6,680,748 that includes only elements related to Customer Satisfaction and Reliability. This resulted in a net reduction for incentive expense of $9,718,091.

- **Accounts 926.203, 926.204 and 926.205—Pension Expense.** Pension expense amortization was increased in the Idaho jurisdiction by $13,993,913, the FERC jurisdiction by $129,964 and in the Oregon jurisdiction by $8,788.

- **Accounts 928.203 and 928.303—Regulatory Commission Expense.** Intervenor Funding was estimated to increase $160,478 by assuming a one-year amortization period, per the following Orders:

- IPUC Order No. 30978—CAPAI for $4,379.
- IPUC Order Nos. 30722—CAPAI for $11,464 and IIPA for $38,472.
- IPUC Order Nos. 30892—CAPAI for $10,510, ICL for $9,854 and IIPA for $20,677.
- OPUC Order No. 11-011—CUB 2011 Funding Grant for $32,350.
- OPUC Order No. 10-406—CUB 2010 Funding Grant for $32,772.

The following O&M discussion has been organized by functional account groups. Within each account group, a general description of the accounts has been provided.

Steam Power Generation

FERC Accounts 500–514

Description

Accounts 500 through 514 include the labor, materials, and expenses incurred to operate and maintain prime movers, generators, and their auxiliary apparatus, switch gear, and other electric equipment used in steam power generation. Additionally, the labor and expenses incurred in the general supervision and direction of maintenance of steam generation facilities are included in these accounts.

Forecast Methodology

Accounts 500–514—Excluding Account 501, Fuel Expense. The 2011 projection for accounts 500–514 was developed by adjusting the 2010 Base with the identified increases provided to IPC from the operating partners of the Thermal Generating Plants. The identified increases were spread to accounts 500–515 (excluding 501) based on 2010 actual amounts in those same accounts.

Account 501—Fuel Expense. The forecast amount included in this account is the same amount used for the October update of the 2010 Annual Power Cost Update (APCU) docket UE 222.

Hydraulic Power Generation

FERC Accounts 535–545

Description

Accounts 535 through 545 include the labor, materials used, and expenses incurred to operate and maintain hydraulic works including structures, reservoirs, dams, waterways, generators, roads and bridges, and expenses directly related to the hydroelectric development outside the generating station, including fish and wildlife and recreational facilities. These accounts also include the labor and expenses incurred in the general supervision and direction of maintenance of hydraulic power generating stations, rents of property of others used, occupied, or operated in connection with hydraulic power generation, including amounts payable to the United States for the occupancy of public lands and reservations for reservoirs, dams, flumes, forebays, penstocks, and power houses.

Forecast Methodology

Accounts 535–545—The projection of accounts 535–545 was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2011 labor projection based on actual 2010 labor. For non-labor, these accounts were projected to be equal to the 2010 Base adjusted by the increase in account 537 for Idaho Fish & Game's projected hatchery increases of $731,856 and by each account's allocated portion of the $4,437,427 non-direct adjustment to non-labor O&M.

Other Power Generation

FERC Accounts 546–557

Description

Accounts 546 through 554 include the operation labor, materials used, and expenses incurred in operating and maintaining prime movers, generators, and electric equipment in other power generating stations. Labor and expenses incurred in the general supervision and direction of maintenance of other power generating stations are also included in these accounts. Account 556 includes labor and expenses incurred in load dispatching activities for system control. System control activities include the production and dispatching of electricity. Account 557 includes production expenses incurred directly in connection with the purchase of electricity which is not specifically provided for in other production expense accounts.

Forecast Methodology

Accounts 546–557—Excluding Account 547, Fuel Expense; Account 555, Purchased Power; and Account 557, Other Expense. The projection of accounts 546–557 was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2011 labor projection based on actual 2010 labor. For non-labor, these accounts were projected to be equal to the 2010 Base and adjusted by a $1,257,722 increase (in account 554) for the 2011 Bennett Mountain Combustor Inspection, and by each account's allocated portion of the $4,437,427 non-direct adjustment to non-labor O&M.

Account 547—Fuel Expense and Account 555—Purchased Power (Excluding 555.050). The forecast amount included in this account is the same amount used for the October update of the 2010 Annual Power Cost Update (APCU) docket UE 222.

Account 555.050—Purchases Power Transmission Losses. This account is projected to increase above the 2010 Base by $359,462. Purchased Power Transmission losses were developed based upon projected volumes and market prices.

Account 557, Other Expense (Excluding 557.000—Other Power Production Expense). These expenses are removed entirely from the test year.

Transmission Expenses

FERC Accounts 560–573

Description

Accounts 560 through 573 include the operation labor, materials used, and expenses incurred in the system planning, operation, executing the reliability coordination function, monitoring, assessing, and operating the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system specified. Additional activities include: processing the hourly, daily, weekly, and monthly transmission service requests using an automated system such as an Open Access Same-Time Information System ("OASIS"); billing to transmission owners for system control and dispatching service; and conducting transmission services studies for proposed transmission interconnections and generation interconnection with the transmission system. These accounts include the labor, materials used, and expenses incurred in the operation of transmission substations, switching stations, and transmission lines. The use of transmission facilities owned by others and rents of property used, occupied, or operated in connection with the transmission system are also part of this account. The accounts also include the labor, materials used, and expenses incurred in the maintenance of structures, computer hardware and software, communication equipment, miscellaneous transmission plant, station equipment, and transmission plant serving the transmission function.

Forecast Methodology

Accounts 560–573—Excluding Account 565.000, Transmission of Electricity by Others (3rd-Party Transmission). The projection of accounts 560–573 was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2011 labor projection based on actual 2010 labor.
For non-labor, these accounts were projected to be equal to the 2010 Base adjusted by $1,414,000 increase for the LIDAR Surveys, and $950,000 increase for Transmission Reliability Projects both to account 563, a $561,169 increase in account 567 for its portion of the BLM rate increase for land rents, and by each account's allocated portion of the $4,437,427 non-direct adjustment to non-labor O&M.

- **Account 565—Transmission of Electricity by Others.** This account was estimated to increase above the 2010 Base by $2,060,093. For the test year, this account was forecasted by combining each individual month's actual expenses for the previous four years and then averaging each month. This average monthly amount is then combined for the twelve months and used as the 2011 forecast.

Distribution Expenses

FERC Accounts 580–598

Description

Accounts 580 through 598 include labor, materials used, and expenses incurred in the general supervision and direction of the operation of the distribution system such as station operation, overhead and underground line operation, meter department operation of customer meters and associated equipment, load dispatching operations, work on customer installations, and inspecting premises. Also included in these accounts are the labor, materials used, and expenses incurred in the general supervision and direction of the maintenance of the distribution system, including maintenance of structures, distribution plant, overhead distribution line facilities, underground distribution line facilities, distribution line transformers, meters, and meter testing equipment.

Forecast Methodology

Accounts 580–598. The projection of accounts 580–598 was developed using both methods described under FERC Account Development above. For labor, accounts 586 and 597 (operation and maintenance of distribution meters) were held equal to the 2010 Base and assuming that, with the new AMI meter, expenses would not increase in 2011. All other accounts received their allocated portion of the total 2011 labor projection based on actual 2010 labor. For non-labor, these accounts were projected to be equal to the 2010 Base adjusted by $135,786 in account 589 for its portion of the BLM rate increase for land rents, and by each account's allocated portion of the $4,437,427 non-direct adjustment to non-labor O&M.

Customer Accounting and Customer Services and Information Expenses

FERC Accounts 901–905 and 907–912

Description

Accounts 901 through 905 include the labor, materials used, and expenses incurred in the general direction and supervision of customer accounting and collecting activities, including reading customer meters, work on customer applications, contracts, orders, credit investigations, billing and accounting, collections, and complaints. These accounts also include the accounting for losses from uncollectible utility revenues. Accounts 907 through 912 include the labor and expenses incurred in customer service and informational activities to encourage safe and efficient use of the utility's service, to encourage conservation of the utility's service, and answer specific inquiries as to proper use of the service and equipment utilizing the service.

Forecast Methodology

Accounts 901–905 and 907–912—Excluding Account 908.131 and 908.132, Idaho and Oregon Energy Efficiency Rider. The projection of accounts 901–905 and 907–912, excluding the Idaho and Oregon Energy Efficiency Rider (energy efficiency expenses), was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2011 labor projection based on actual 2010 labor. Additionally, account 902 was reduced by $1,973,938 accounting for the savings attributable to AMI. For non-labor, these accounts were projected to be equal to the 2010 Base and by each account's allocated portion of the $4,437,427 non-direct adjustment to non-labor O&M.

Account 908.131 and 908.132—Idaho and Oregon Energy Efficiency Rider. The expenses associated with the Idaho and Oregon Energy Efficiency Riders have been excluded from the 2011 test year in their entirety (IPUC Order No. 30189).

Administration and General Expenses ("A&G")

FERC Accounts 920–935

Description

Accounts 920 through 935 include activities undertaken in connection with the utility's general and administrative operations that are assignable to specific administrative or general departments and are not specifically provided for in other accounts. A&G accounts include: (1) compensation of officers, executives, and other employees of the utility which are properly chargeable to utility operations but not chargeable directly to a particular operating function, (2) office supplies and expenses, (3) fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function, (4) insurance or reserve accruals to protect the utility against losses and damages to owned or leased property used in its utility operations, (5) payments for employee accident, sickness, hospital, and death benefits or insurance, (6) payments to municipal or other governmental authorities, (7) the cost of materials, supplies, and services furnished to such authorities without reimbursement in compliance with franchise, ordinance, or similar requirements, (8) expenses incurred by the utility in connection with formal cases before regulatory commissions or other regulatory bodies, (9) regulatory fees assessed against the utility, (10) commission expenses, (11) payments made to the United States for the administration of the Federal Power Act, (12) materials used and expenses incurred in advertising and related activities, (13) rents properly includable in operating expenses for the property of others used, occupied, or operated in connection with customer accounts, customer service, and informational sales and general and administrative functions of the utility, and (14) operation and maintenance of transportation equipment and the maintenance of utility property which is not chargeable directly to a particular operating function.

Forecast Methodology

Accounts 920–935—Excluding Account 920.001, Incentive Expense, 926.203, 926.204, 926.205, Pension Expense and part of 928.202, 928.203, and 928.303, Regulatory Commission Expenses. The projection of accounts 920–935, excluding incentive, was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2011 labor projection based on actual 2010 labor. For non-labor, these accounts were projected to be equal to the 2010 Base adjusted upward by $155,201 in non-recurring amortization of the FERC OFA refund in account 928, and by $128,026, $12,173 and $4,070 increase in accounts 921, 931 and 935, respectively for their portion of the BLM rate increase for land rent. These accounts also received each account's allocated portion of the $4,437,427 non-direct adjustment to non-labor O&M.

Account 920.001—Incentive Expense. In the 2008 Idaho General Rate case order (IPUC Order No. 30722) the Commission directed IPC to only include a normalized incentive that "is directly related to improving service or reducing costs to customers." IPC therefore, included in its projection only the normalized level of incentive attributable to Customer Satisfaction and Reliability. As a result, for the 2011 test year, IPC removed its entire 2010 actual incentive expense of $16,398,839 from its 2010 Base and replaced that amount with its projected 2011 normalized incentive of $6,680,748 that includes only those elements related to Customer Satisfaction and Reliability. This resulted in a net reduction for incentive expense of $9,718,091.

Accounts 926.203, 926.204, and 926.205—Pension Expense. For the Oregon jurisdiction the IPC's actuary (Milliman, Inc.) provided a total 2011 net periodic pension expense estimate (SFAS 87) of $27,954,213 of which Oregon's allocated portion is $893,024. This is an $8,788 increase over the amount included in the 2010 Base.

In the Idaho jurisdiction, per IPUC Order No. 31091, IPC is currently recovering $5,416,796 of its cash contributions to its defined benefit pension plan over a one-year period that began in June 2010. As a result of this Order, included in the 2010 Base is seven months of amortization expense for $3,159,800. IPC is including in its forecast the additional five months of amortization for $2,256,996. In addition, IPC has requested in Case No. IPC-E-11-04 recovery of an additional $11,736,917 for cash contributions made in 2010 which is also included in the forecast, bringing the total requested recovery amount for the Idaho jurisdictional cash payments to $17,153,713. Therefore, IPC has included in its forecast adjustment an additional $13,993,913 in amortization expense for 2011.

Since the FERC jurisdiction follows the Idaho jurisdiction for treatment of its portion of pension expense (cash basis), IPC has included an additional $129,964 in amortization in its estimate above the existing $60,986 that is included in the 2010 Base.

Account 928—Regulatory Commission Expenses. This account was increased by $155,201 due to three months fewer amortization periods for the amortization of the reimbursement of FERC OFA (IPUC Order No. 30722) than what was in 2010 actuals. This account was also increased for intervenor funding by $160,478 that was directed in IPUC Order Nos. 30978, 30722 and 30892 for $4,379, $49,936, $41,041, respectively and OPUC Order Nos. 11-011 and 10-406 for $32,350 and $32.772, respectively. IPC has assumed a one year amortization for intervenor funding. Account 928 also received its allocated portion of the $4,437,427 non-direct adjustment to non-labor O&M.

Accounts 908.131 and 908.132—Idaho and Oregon Energy Efficiency Rider Expenses. The amounts in these accounts have been removed from the test year in their entirety per IPUC Order No. 30189.

Forecast Adjustment E—Depreciation and Amortization Expense

Table 6—FERC Accounts 403 and 404

Description

Account 403 includes depreciation expense for all classes of depreciable electric plant in service except such depreciation expense as is chargeable to clearing accounts or to account 416, Costs and Expenses of Merchandising, Jobbing and Contract Work. Account 404 includes amortization charges applicable to amounts included in the electric plant accounts for limited-term franchises, licenses, patent rights, limited-term interest in land, and expenditures on leased property where the service life of the improvements is terminable by action of the lease. The charges to this account are such as to distribute the book cost of each investment as evenly as may be over the period of its benefit to the utility.

Forecast Methodology

Forecast Adjustment E increases Depreciation and Amortization Expense (accounts 403 and 404) by $4,974,317 above the 2010 Base

Depreciation and amortization rates were applied to the monthly estimated plant balances (see the Electric Plant in Service discussion in the Rate Base Components section). The depreciation rates authorized by both OPUC Order No. 09-317 and IPUC Order No. 30639 were used for the entire 2011 test year. Several FERC plant accounts have sub-accounts, for which the individual sub-account data was used to calculate a composite rate and applied at the major account level.

For plant accounts 392, Transportation Equipment; 396, Power Operated Equipment; 312, Boiler Plant Equipment; and 397, Communication Equipment, either all or part of the depreciation expense is recorded to other accounts and not account 403. The account 312, Boiler Plant Equipment, and account 397, Communication Equipment, depreciation amounts were calculated using the actual 312.300 and 397.300 accrual for December 2010.

Forecast Adjustment F—Electric Plant/Regulatory Assets—Amortization, Adjustments, Gains and Losses

Table 6—FERC Accounts 406, 411.6, and 411.7

Description

Account 406 is debited or credited, as the case may be, with amounts includable in operating expenses, pursuant to approval or order of the Commission, for the purpose of providing for the extinguishment of the amount in account 114, Electric Plant Acquisition Adjustments. Accounts 411.6 and 411.7 includes, as approved by the Commission, amounts relating to gains and losses from the disposition of future use utility plant, including amounts which were previously recorded in and transferred from account 105, Electric Plant Held for Future Use.

Forecast Methodology

Forecast Adjustment F is $0, resulting in the Amortization of Electric Plant Acquisition Adjustments (account 406) and Gains and Losses from Disposition of Utility Plant (account 411.6 and 411.7) remaining the same as the 2010 Base.

Account 406 is projected for 2011 to remain the same as the 2010 Base. Included in this account is the amortization of the Prairie Power acquisition adjustment of account 114 over 233 months at $1,894 per month. The amount in account 114 will be fully amortized in July 2012.

Accounts 411.6 and 411.7 do not have a forecast since there is no plan to sell utility plant in 2011.

Forecast Adjustment G—Regulatory Debits and Credits

Table 8—FERC Account 407.3

Description

Account 407.3 is debited, when appropriate, with the amounts credited to account 254, Other Regulatory Liabilities, to record regulatory liabilities imposed on the utility by the ratemaking actions of regulatory agencies. This account is also debited, when appropriate, with the amounts credited to account 182.3, Other Regulatory Assets, concurrent with the recovery of such amounts in rates.

Forecast Methodology

Forecast Adjustment G increases Regulatory Debits (account 407.3) by $5,802 above the 2010 Base.

IPC has recorded a regulatory asset in account 182.339 for the "capitalized" portion of the net periodic pension costs since August 2007. This capitalized portion is comprised of the Oregon jurisdictional share of net periodic pension cost for each year multiplied by that year's capitalization percentage, which is determined based on an analysis of the year's labor costs to determine the percentage of those costs that were ultimately recorded to construction.
The capitalization percentage for 2010 was approximately 30.57 percent, which is the assumed percentage for 2011 and 2012. IPC projects a balance for the Oregon capitalized pension costs of $1,323,161 by December 31, 2011. As a result of the capitalized balance, IPC has estimated the amortization of this amount in account 407.3 to be $27,757 for 2011, an increase of $5,802 over the 2010 Base.

Forecast Adjustment H—Taxes Other than Income Taxes

Table 7—FERC Account 408.1

Description

Account 408.1 includes those taxes other than income taxes which relate to utility operating income. This account is maintained so as to allow ready identification of the various classes of taxes relating to utility operation, plant leased to others, and other operating income.

Forecast Methodology

Forecast Adjustment H increases Taxes Other Than Income (Accounts 408.1) by $3,454,070 above the 2010 Base.

The 2011 forecast methodology for Taxes Other Than Income Taxes was based on a combination of known adjustments arising from specifics of the particular account activity and a carry forward of the 2010 Base amounts.

Real and Personal Property Taxes

The Idaho property taxes were $10.9 million, $12.6 million, and $14.9 million in 2008, 2009 and 2010, respectively. The property tax increases can be attributable to the increase in market value determined by the Idaho Tax Commission (a result from an increase in utility plant investment along with an increase in net operating income), an increase in local taxing districts budget requirements and a shift in tax burden (residential home values declining).

The methodology used to project property taxes for the 2011 test year is the same estimation process used for establishing the annual property tax accrual for IPC financial statements. Property taxes are estimated using both an appraisal and levy methodology. For the appraisal methodology, actual appraisal data is used to the extent known and each state's historical appraisal methodologies and trends are used in determining the appraisal amount. For the tax levy methodology, the state's historical levy data and local government budget policy is used to estimate levies.

Idaho kWh Taxes

Test year 2011 kWh taxes were projected based on normalized hydro conditions and normalized consumption.

Regulatory Commission Fees

The 2011 Idaho regulatory fee was estimated by using the 2010 actual payment. IPC's intrastate gross revenue and the governor's budget recommendation was within 1% of prior year therefore, it was determined the 2010 Base was an appropriate estimate for 2011. The Oregon regulatory fee consists of two fees, Oregon PUC fee and Oregon Department of Energy fee. For the test year 2011, the Oregon PUC fee was the actual 2011 fee and for the Oregon Department of Energy fee, the 2011 estimate was based upon prior year's tax rate multiplied times the current year revenue.

Licenses

The 2011 Wyoming license was estimated using the prior year's tax rate applied to the estimated 2011 Wyoming assessed value. The 2011 Shoshone–Bannock license fee was estimated using the prior year's actual.

Franchises

The Oregon franchise tax was determined by applying a city franchise rate to its corresponding electric revenue. For 2011, each cities applicable tax rate was applied to estimated city revenue.

Forecast Adjustment I—Idaho Energy Resources Co. ("IERCO") Cost of Service Components

FERC Accounts 418.1 and 419

Description

Account 418.1 includes the utility's equity in the earnings or losses of subsidiary companies for the year. Account 419 includes interest revenues on securities, loans, notes, advances, special deposits, tax refunds, all other interest-bearing assets, and dividends on stocks of other companies, whether the securities on which the interest and dividends are received are carried as investments or included in sinking or other special fund accounts.

Forecast Methodology

Forecast Adjustment I decreases Idaho Energy Resources Co. ("IERCO") Cost of Service Components (Accounts 418.1 and 419) by $945,499 below the 2010 Base of $7,575,497 resulting in a projected 2011 net income of $6,629,998.

IPC owns 100% of Idaho Energy Resource Company ("IERCO"), which has a one-third joint venture interest in Bridger Coal Company ("BCC"), a mine that supplies coal to the Jim Bridger plant. PacifiCorp, Inc. owns the remaining two-thirds interest and is the mine's operating partner. As a one-third owner in BCC, IERCO is entitled to one-third of the BCC net income and cash flows.

The projected 2011 net income of $6,629,998 incorporates PacifiCorp's projected activity for the BCC mine. IERCO's overriding royalties are determined by the location and lease under which BCC is mining. The three leases are with the BLM, Union Pacific Railroad, and State of Wyoming, and each lease pays at a different rate. The overriding royalty was granted to BCC from IERCO, who in turn received them from IPC as advance royalties in the past. Coal royalty payments have no impact on IERCO's net income as revenue is recognized when paid by BCC, and expense recognized when remitted to IPC.

Income taxes are calculated at the federal tax rate of 35% as Wyoming has no state income tax. Taxes are accrued and paid during the calendar year.

As discussed in the Rate Base Components section that follows, IERCO maintains an intercompany note with IPC that accrues interest monthly at IPC's short-term borrowing rate, which is projected to be .75% in 2011. For purposes of the Cost of Service Component of IERCO, the intercompany interest expense net of income tax is added back to increase IERCO's net income.

RATE BASE COMPONENTS

Forecast Adjustment J—Electric Plant in Service

Table 1—FERC Account 101

Description

This account includes the original cost of electric plant that is included in accounts 301 to 399 (referred to herein as plant accounts). It is described as being owned and used by the utility in its electric utility operations and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. The cost of additions to and improvements of property leased from others, which are includable in this account, are recorded in subdivisions separate and distinct from those relating to owned property.

Forecast Methodology

Forecast Adjustment K increases Electric Plant In Service (Account 101) by $165,872,190 above the 2010 Base. Electric Plant In Service has been presented using a thirteen-month average.

The methodologies used for plant additions and retirements are described below.

Plant Additions to Electric Plant In Service

Projected 2011 plant additions to Electric Plant In Service were developed based on the size of Construction Work in Process ("CWIP") projects as of year-end 2010 plus the expected 2011 capital expenditures. These capital projects were segregated into pools of greater than and less than $2 million. Capital projects greater than $2 million were considered to be known and measureable. For capital projects less than $2 million, an historical methodology was developed. Once CWIP project types for both pools were determined, the results were then combined and allocated to FERC plant accounts 301 through 399 using a five year historical average.
This methodology is consistent with that used in Idaho's 2008 General Rate Case (Case No. IPC-E-08-10) and Oregon 2009 General Rate Case (Docket No. UE 213).

Projected 2011 Plant Additions

Capital Projects in Excess of $2 Million. Large capital projects with total costs in excess of $2 million were determined to be known and measurable adjustments for the 2011 unadjusted test year. Actual capital expenditures in CWIP as of year-end 2010, plus expected 2011 capital expenditures were used in determining the amount that would close to plant by year-end 2011. Allowance for Funds Used During Construction ("AFUDC") was accrued on the CWIP balances prior to their projected close. In addition, these projects' capital account balances, projected expenditures, and the timing of closes to plant were reviewed by business unit managers familiar with the projects.

The total amounts for the plant additions in the pool of over $2 million in capital expenditures were assigned CWIP project types based on the nature of each individual project.

Capital Projects Less Than $2 Million. In recognition of the current uncertain market conditions, anticipated 2011 plant closings were set equal to actual 2010 plant closings for similar-sized projects.

The total amounts for the plant additions in the pool of under $2 million in capital expenditures were then allocated to the CWIP project types based on a three-year historical average.

All vehicle purchases were considered in total as a single project for this purpose.

Allocation to FERC Plant Account

The above CWIP project type pools were combined for final allocation to FERC plant accounts. For this allocation, actual final closings from CWIP account 107 into Electric Plant In Service, account 101 were analyzed for the five-year period 2005 through 2009. Final closing amounts in the PeopleSoft Asset Management system were used to allocate closings to plant accounts rather than pre-close amounts. Final closes represent the "as built" property units after the construction and work order has been completed and reconciled, whereas pre-closes are based on work order estimates and may not be reflective of the final close distribution. For each CWIP project type, the percentage allocation to FERC plant accounts 301 through 399 was determined by the ratio of the five-year historical plant account closing for that CWIP project type.

Retirements from Electric Plant In Service

Retirements were analyzed for the five-year period 2005 through 2009. Retirements by FERC plant account were determined and compared to the closings by FERC plant account for the same period. Retirements by FERC plant account were estimated by calculating the historical percentage of retirements to additions for the five-year period.

The following FERC plant accounts have known retirement dates based on vintage layers and were not estimated:

- Account 302—Software
- Account 303—Franchises and Consents
- Account 391—Furniture
- Account 393—Stores Equipment
- Account 394—Shop Tools
- Account 395—Laboratory Equipment
- Account 397—Communication Equipment
- Account 398—Miscellaneous Equipment

Forecast Adjustments K & L—Accumulated Provision for Depreciation and Amortization

Table 2—FERC Accounts 108 and 111

Description

Account 108 is credited for amounts charged to account 403, Depreciation Expense, or to clearing accounts for current depreciation expense for electric plant in service. At the time of retirement of depreciable electric utility plant, this account is charged with the book cost of the property retired and cost of removal and then credited with the salvage value and any other amounts recovered such as insurance. When retired, costs of removal and salvage are originally entered in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder. Upon completion of the work order, the proper distribution to subdivisions of this account shall be made for general ledger and balance sheet purposes as a single composite provision for depreciation. For purposes of analysis, however, each utility shall maintain subsidiary records in which this account is segregated according to the functional classification of electric plant in service. Account 111 is credited with amounts charged to account 404, Amortization of Limited-Term Electric Plant, for the current amortization of limited-term electric plant investments.

Forecast Methodology

Forecast Adjustments L & M increase Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111) by $63,737,756 and $2,820,040 respectively, above the 2010 Base. The accumulated provision for depreciation and amortization has been presented using a thirteen-month average. The 2011 forecast was developed by first determining the 2010 monthly balances and then building upon that to determine the 2011 thirteen-month account balances. The process began with the year-end 2010 accumulated depreciation and amortization account balances which were rolled forward monthly using the estimated 2011 depreciation and amortization expense accruals, retirements, salvage, and removal costs. See account 403 and 404 in the Cost of Service Components section for discussion with respect to the depreciation and amortization accrual calculation and Electric Plant In Service, account 101 in the Rate Base Components section for discussion of the method of determining retirements. The five-year (2006–2010) average salvage, removal costs, and retirements were then calculated. The salvage and removal averages as a percentage of the retirement average were used to estimate monthly salvage and removal costs. Those amounts were allocated to the transmission and distribution FERC plant accounts in their respective ratio to estimated retirements.

Forecast Adjustment M—Materials and Supplies

Table 3—FERC Accounts 154 and 163

Description

Account 154 includes the cost of materials purchased primarily for use in the utility business for construction, operation, and maintenance purposes. Materials and supplies issued are credited hereto and charged to the appropriate construction, operating expense, or other account on the basis of a unit price determined by the method of inventory accounting. Account 163 includes the cost of supervision, labor, and expenses incurred in the operation of general storerooms, including purchasing, storage, handling, and distribution of materials and supplies. This account is cleared by adding to the cost of materials and supplies issued a suitable loading charge which distributes the expense equitably over stores issues. The balance in the account at the close of the year shall not exceed the amount of stores expenses reasonably attributable to the inventory of materials and supplies.

Forecast Methodology

Forecast Adjustment N reflects a $657,159 decrease in Materials and Supplies (accounts 154 and 163) below the 2010 Base.

The thirteen-month average decrease was due partially to a concerted effort to reduce inventories, as a result of the economic slow-down. Specifically, account 154.220 from the December 2009 to December 2010 decreased by $1,481,473. Additionally, IPC over cleared overheads included in the 163 accounts by $935,723. However, while the thirteen-month average reflects a decrease to rate base, the December 2011 year-end balance is expected to increase over the 2010 year-end balance by $1,590,713 based on the following:

- M & S Steam Plant is forecasted to increase $241,336 based on the January 2009 through February 2011 actuals.
- The new Langley Gulch gas plant is expected to cause an increase in inventories by $250,000.
- Stores Expense Undistributed was increased $1,071,985 to the amount forecasted by the Financial Stores Loading model at December 31, 2011. As stated above, the 2010 ending balance in these accounts was artificially low due to inventory issues being greater than projected in the fourth quarter 2010.
- Stores Expense Steam Plant is estimated to decrease $495,149 based on trending actual month-end balances for the time period January 2009 through February 2011.
- The balance in the Sales Tax account (163500) is forecasted to increase $522,541 due to the 2010 ending balance in this account being lower than required due to timing variances with issues and invoice processing.

Forecast Adjustment N—Other Deferred Programs

Table 3—FERC Accounts 182.3 and 186

Description

This account includes the amounts of regulatory assets not includable in other accounts resulting from the ratemaking actions of regulatory agencies.

Forecast Methodology

Forecast Adjustment O increases Other Deferred Programs (Accounts 182.3 and 186) by $146,580 above the 2010 Base.

Accounts 186.722 and 186.770—American Falls Bond Refinancing, IPUC Order No. 25880. These deferred costs are financing costs related to American Falls Bond issuances. The total monthly amortization of these two bonds is $5,212 per month or $62,552 per year. IPC has reduced the 2010 Base for one year of additional depreciation for $62,552, resulting in a total deferral of $823,593.

Account 182.349—Intervenor Funding, IPUC Order No. 30722. This account includes intervenor funding ordered in the 2008 General Rate Case (Case No. IPC-E-08-10). In that case, IPC was ordered to pay the Community Action Partnership Association of Idaho (“CAPAI”) $9,183 in costs as a result of their participation in the case. IPC has assumed a one-year amortization period for recovery of these costs in this case. This reduced the deferral by the 2010 Base of $10,572 including accrued interest, resulting in a total deferral forecast of $0.

Account 182350—Intervenor Funding, IPUC Order No. 30722. This account includes intervenor funding ordered in the 2008 General Rate Case (Case No. IPC-E-08-10). In that case, IPC was ordered to pay the Idaho Irrigation Pumpers Association, Inc. (“Irrigators”) $30,817 in fees and expenses as a result of their participation in the case. IPC has assumed a one-year amortization period for recovery of these costs in this case. This reduced the deferral by the 2010 Base of $35,480 including accrued interest, resulting in a total deferral forecast of $0.

Account 182.345—Citizens Utility Board (“CUB”) 2010 Funding Grant, OPUC Order No. 10-406. IPC was ordered in Docket UM 1504(1) to fund $30,000 to CUB pursuant to the terms of the Intervenor Funding Agreement by and among IPC and CUB and approved by the OPUC in Order no. 10-396. As a result, IPC has assumed a one-year amortization period for recovery of these costs in this case. This reduced the deferral by the 2010 Base of $30,100 including accrued interest, resulting in a total deferral balance of $0.

Account 182.339—SFAS 87 Capitalized Pension Costs, OPUC Order No. 10-064. IPC included a forecast adjustment of $383,271 for its capitalized portion of its SFAS 87 Capitalized Pension Costs. This brings the total 2011 estimate to $1,323,161.

Account 182.369—Grid West Loans, OPUC Order No. 06-483. IPC has included a reduction to its 2010 Base of $14,191 for one year of additional amortization, bringing the test year deferral balance to $44,937.

Account 182.304—Grid West Loans, FERC Portion. IPC has included a reduction to its 2010 Base for $83,796 for one year of additional amortization, bringing the test year deferral balance to $111,728.

Forecast Adjustment O—Customer Advances for Construction ("CAC")

Table 3—FERC Account 252

Description

Account 252 includes advances by customers for construction which are to be partially or wholly refunded. When a customer is refunded the entire amount to which he or she is entitled according to the agreement or rule under which the advance was made, any remaining balance is credited to the appropriate plant account.

Forecast Methodology

Forecast Adjustment Q decreases the Customer Advances for Construction (Account 252) 2010 Base by $6,304,446, based on an estimated thirteen-month average balance.

IPC investigated various methods to forecast this account, including the average dollar balance per customer methodology that was used in the 2008 Idaho General Rate Case (IPC-E-08-10) and Oregon 2009 General Rate Case (Docket No. UE 213). However, because of new Rule H changes this method became inaccurate. Therefore, IPC determined that because customer advances are driven primarily by customer growth, the most reasonable method was to start with the December 2010 Base for account 252, removing all balances related to Construction Work in Progress, then reducing the balance by the subdivision lots completed in 2006, as these will be either refunded or absorbed by the end of 2011. IPC then reduced the balance further by annualizing the 2010 lot refunds for work completed from 2007 to 2009 as the estimate for 2011 lot refunds that fall inside the 5-year period for refunds. This method reflects the IPC's anticipation that market conditions in 2011 will be similar to those existing in 2010. Finally, IPC added in the estimated ending unusual conditions and network transmission upgrade balances. IPC's removal of balances associated with Construction Work in Progress is because these should not be included to reduce rate base since Construction Work in Progress is not a rate-based item. Please see the analysis in the following table:

2011 Forecast of Customer Advances	Total
12/31/10 LXMN lot refund balance excluding net work transmission upgrades and unusual conditions	$19,146,937
2006 lot refund balance to be refunded or absorbed in 2011	(4,497,506)
2011 estimated refunds estimated ending balances	(831,772)
Unusual conditions refunds estimated ending balance	973,225
Network transmission upgrades estimated balance excluding work in progress	837,500
12/31/11 estimated customer advances excluding work in progress and unusual conditions	**$15,628,384**[1]

[1] This amount represents the estimated year-end balance. IPC has estimated the thirteen-month balance of $17,261,533 based on the shape of the 2010 actual thirteen-month average balance.

Forecast Adjustment P—Idaho Energy Resources Co. (“IERCO”) Rate Base

Table 3—FERC Accounts 123.1, 186, and 145

Description

Account 123.1 includes the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account is credited with any dividends declared by such subsidiaries. This account is maintained in such a manner as to show separately for each subsidiary: (1) the cost of such investments in the securities of the subsidiary at the time of acquisition, (2) the amount of equity in the subsidiary’s undistributed net earnings or net losses since acquisition, and (3) advances or loans to such subsidiary. Account 145 represents notes receivable from associated companies. Account 186 includes all debits not elsewhere provided for, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, which are in process or amortization and items the proper final disposition of which is uncertain.

Forecast Methodology

Forecast Adjustment R increases Idaho Energy Resources Co. (“IERCO”) Rate Base (Account 123.1,186 and 145) by $154,130 above the 2010 Base.

IPC’s projected 2011 investment in IERCO is based on actual activity for 2010 at the Bridger Coal Company (“BCC”) mine that supplies coal to the Jim Bridger thermal plant. As a one-third owner in BCC, IERCO is entitled to 33% of the BCC net income and cash flows.

- **Account 123.1—Investment in IERCO.** The 2011 thirteen-month average investment in IERCO balance is projected to increase $7,609,643 from the 2010 Base thirteen-month average balance of $67,582,237 to $75,191,880. IERCO’s investment in BCC is accounted for using the equity method. BCC income, IERCO income, and IERCO capital contributions to BCC increase the investment balance; while BCC dividend distributions to IERCO reduce the investment balance. The $7,609,643 increase is due to reinvesting one year worth of after tax earnings into BCC. No dividend assumptions were made during the forecast test year. Instead, any extra cash remaining after paying operating expenses and capital investment are returned to IPC via the intercompany note (see below for discussion of account 145—IERCO Intercompany Note).

- **Account 186—Prepaid Coal Royalties.** The 2011 thirteen-month average balance is projected to decrease $68,132 from the 2010 Base thirteen-month average balance of $1,464,357 to $1,396,225. BCC overriding coal royalties are determined by the location and lease under which BCC is mining. The overriding royalty was granted to BCC from IERCO, who in turn received them from IPC as advance royalties in the past. Although coal royalty payments have no impact on IERCO's net income, because revenue is recognized when paid by BCC and expense recognized when remitted back to IPC, the payment flow serves to reduce the account 186 balance.

- **Account 145—Notes Payable To/Receivable from Subsidiary.** The 2011 thirteen-month average balance is projected to decrease $7,387,381 from the 2010 Base thirteen-month average balance of $19,880,651 to $12,493,269. The IERCO intercompany note is the funding mechanism whereby IERCO not only receives distributions from and makes capital contributions to BBC, but also pays income taxes and dividends to IPC. The intercompany note activity is based on the projected 2011 BCC operating and capital budgets. Because capital expenditures have been leveling off, BBC is projected to have extra cash in 2011 to reduce the note balance. Interest on the intercompany note is based on IPC's short-term borrowing rates and accrues monthly. The average interest rate used is .75%.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
______________________________________	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

KELLEY NOE

July 29, 2011

Q. Please state your name and business address.

A. My name is Kelley Noe. 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 ("Idaho Power" or "Company") as a Regulatory Analyst II.

Q. Please describe your educational background.

A. In May of 2004, I received a Bachelor of Business Administration in Finance from Boise State University.

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

A. In September 2006, I accepted a position at Idaho Power as a Financial Analyst in the Finance Department. My responsibilities as a Financial Analyst were two-fold. For the credit analysis portion of my position, I was responsible for gathering counterparty credit and financial information, preparing a risk analysis, and then approving an appropriate credit limit assignment. When necessary, I negotiated security or collateral documents that met corporate credit standards and tracked the documents to ensure they were current and up-to-date. In addition, I prepared monthly credit reports for management. The other responsibilities in my position included providing the financial support for the Grid Operations, Planning, and Operations Analysis and Development groups. This included preparing studies, reports, analyses, and recommendations in areas such as budgets, forecasts, capital expenditure proposals, financial plans, and regulatory requirements. In October 2010, I accepted a Regulatory Analyst II position within the Regulatory Affairs Department of the Company. My duties as a Regulatory Analyst II include gathering, analyzing, and coordinating data from various departments throughout the Company required for development of jurisdictional separation studies, as well as other analyses that may be required.

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

A. I am sponsoring testimony to summarize the annualizing adjustments to the 2011 unadjusted forecast test year data used by the Company for purposes of forecasting the Company's rate base, revenues, and expenses for the 2011 Test Year. My testimony will also quantify the Oregon Jurisdictional Revenue Requirement resulting from the Jurisdictional Separation Study ("JSS") for the 12 months ending December 31, 2011.

Q. Have you prepared exhibits for this proceeding?

A. Yes. I am offering the following exhibits:

1. Exhibit 901, Major Plant Additions Annualized for 2011
2. Exhibit 902, Depreciation & Amortization Annualizing Adjustments
3. Exhibit 903, Summary of Payroll-Related Annualizing Adjustments
4. Exhibit 904, Development of System Revenue Requirement
5. Exhibit 905, Jurisdictional Separation Study - Oregon Revenue Requirement

Q. Could you briefly summarize how the Company developed its 2011 Test Year?

A. Yes. As described in the testimonies and exhibits of Mr. Douglas N. Jones and Mr. Timothy E. Tatum, the development of the 2011 Test Year begins with 2010 actual financial data ("2010 Actuals"). The 2010 Actuals were adjusted to reflect currently approved ratemaking adjustments and arrive at 2010 adjusted actual financial information ("2010 Base"). The 2010 Base was then adjusted to reach 2011 forecasted financial levels ("2011 Unadjusted Test Year"). After the 2011 Unadjusted Test Year figures were compiled, they were provided to me as the starting point for the development of the Company's total 2011 Test Year figures used in this filing.

Q. Were any additional adjustments made to the 2011 Unadjusted Test Year amounts to reach the Company's total 2011 Test Year figures?

A. Yes. Exhibits 901 through 903 illustrate the annualizing adjustments used to develop the total 2011 rate base and net income figures used in the Company's 2011 Test Year.

Q. Please describe the role of annualizing adjustments in this filing.

A. At Mr. Tatum's direction, I performed a number of annualizing adjustments to amounts that are incurred within the test year, but need to be reflected for the full year on an ongoing basis.

Q. Please describe the annualizing adjustments made for "Major Plant Additions."

A. Major Plant Additions illustrated in Exhibit 901 are defined as those investments exceeding $2 million that will close to the Company's electric plant in service accounts during the calendar year 2011. A month-by-month forecast of 2011 electric plant in service and the 13-month average balances provided by Mr. Jones form the beginning point for the analysis. Annualizing adjustments are applied only to the 2011 plant additions that qualify as Major Plant Additions to establish the amount of investment that would have been recorded had the plant been in service throughout the entire year. The difference between what had been forecast for these investments in the initial analysis compared to the annualized forecast, as illustrated in column 3 – Net Annualizing Adjustments, is the $31,599,458 annualizing adjustment for the Company's electric plant in service investment in this filing. Additional annualizing adjustments associated with Major Plant Additions include $132,419 in property taxes (column 6 – Annual Composite Property Tax) and $12,008 in property insurance (column 8 – Annual Insurance Expense).

Q. Please describe Exhibit 902 - Depreciation & Amortization Annualizing Adjustments.

A. Depreciation and amortization expenses are forecast on a month-by-month basis during 2011 and summarized in the column entitled “Forecasted Depreciation Expense.” The expenses for December 2011 are multiplied by 12 to calculate the “Annualized Depreciation Expense.” The difference between these two columns equals the “Annualizing Adjustment” of $2,225,161 depreciation expense and $189,455 amortization expense. Adjustments of $1,125,683 to Accumulated Depreciation and $94,728 to Accumulated Amortization, illustrated as the “Reserve Adjustment,” are conventionally computed as half the expense amounts.

Q. Please continue by explaining Exhibit 903, Summary of Payroll-Related Annualizing Adjustments.

A. There are two additional labor-related annualizing adjustments in this filing totaling $4,332,883.

The first adjustment utilizes 2010 actual labor data as a proxy to annualize 2011 payroll and reflect an entire year of expense at that year-end level. Because the method applied to forecast the 2011 operations and maintenance (“O&M”) labor expense (detailed in the testimony by Mr. Tatum) provided only a forecast of the annual 2011 O&M labor expense, a December labor expense amount from which a conventional annualizing labor adjustment could be calculated was not known. Therefore, an annualizing adjustment based upon actual 2010 labor was calculated and used as a proxy to adjust the O&M labor total for the 2011 Test Year. After applying the Company’s Operations & Maintenance and benefit loading percentages, the annualizing adjustment is $1,955,023.

The second adjustment of $2,377,859 reflects the projected 2012 salary structure adjustment of 2 percent. This adjustment was applied to the annualized

2011 payroll and has been adjusted by the Company's O&M and benefit loading percentages.

Q. Please describe Exhibit 904, Development of System Revenue Requirement.

A. Exhibit 904 provides the development of the adjusted total electric system rate base and net income for the test year ending December 31, 2011.

The first set of data, displayed in column 3 - "2010 Actual", is the unadjusted 2010 actual results of operations provided by Mr. Jones. The adjustments proposed by the Company for purposes of developing the 2011 adjusted total electric system combined rate base and net income are shown in columns 4, 6, and 8 with the total system adjusted test year rate base, expenses, and revenues summarized in column 9. The columns are as follows:

(1) Column 4, titled "2010 Actual Adjustments" was provided by Mr. Jones and Mr. Scott Wright. It reflects currently approved regulatory adjustments that should be applied to the 2010 actual results prior to applying methods to adjust to 2011 levels;

(2) Column 5, titled "2010 Base" is the adjusted base to which the methods to create a 2011 Test Year were applied;

(3) Column 6, titled "Forecast Adjustments" reflects the results of the various methods from the Forecast Methodology Manual sponsored by Mr. Tatum and detailed in his testimony, that were used to adjust totals from the 2010 Base to a 2011 Unadjusted Test Year.

(4) Column 7, titled "2011 Unadjusted Test Year" includes the resulting dataset after the standard regulatory adjustments and various methods were applied;

(5) Column 8, titled "Annualizing Adjustment" includes standard annualizing adjustments, to reflect changes that occur within the test year,

but need to be incorporated for the full year on an ongoing basis. All annualizing adjustments included in this filing were discussed earlier in my testimony.

(6) Column 9, titled "2011 Test Year" is the resulting dataset for the 2011 Test Year (12 months ending December 31, 2011).

Q. Please describe page 2 of Exhibit 904.

A. Page 2 of Exhibit 904 summarizes the development of rate base components for the 2011 Test Year. The total combined rate base, based on actual, unadjusted 2010 results was $2,420,460,776 (column 3, line 63). After adjustments, the total combined rate base for the 2011 Test Year increases to $2,499,296,901 (column 9, line 63).

Page 2 of Exhibit 904 also includes the development of the total system net income for the 12 months ending December 31, 2011. Operating revenues are summarized on line 69. Total operating expenses are summarized on line 80.

Q. Have you prepared an exhibit that sets forth the Oregon jurisdictional revenue deficiency?

A. Yes. I prepared Exhibit 905, titled "Jurisdictional Separation Study – Oregon Revenue Requirement" consisting of 35 pages.

Q. Please describe Exhibit 905.

A. Exhibit 905 is the complete Jurisdictional Separation Study report detailing the allocation of each component of rate base, operating revenues, and expenses by Federal Energy Regulatory Commission ("FERC") account resulting in the Oregon jurisdictional revenue deficiency. The JSS is organized as follows:

- Summary of Results
- Table 1 - Electric Plant in Service
- Table 2 - Accumulated Provision for Depreciation (and Amortization)

- Table 3 - Additions & Deductions to Rate Base
- Table 4 - Operating Revenues
- Table 5 - Operation & Maintenance Expenses
- Table 6 - Depreciation & Amortization Expense
- Table 7 - Taxes Other Than Income Taxes
- Table 8 - Regulatory Debits & Credits
- Table 9 - Income Taxes
- Table 10 - Calculation of Federal Income Tax
- Table 11 – Oregon State Income Tax
- Table 12 – Idaho State Income Tax and Other State Income Tax
- Table 13 - Development of Labor Related Allocator
- Table 14 - Allocation Factors
- Table 15 - Allocation Factors-Ratios

Q. Please discuss the methodology used to jurisdictionally separate costs in the preparation of this study.

A. A three-step process was used to separate costs among jurisdictions. The three steps are classification, functionalization, and allocation of costs. In all three steps, recognition was given to the way in which costs are incurred by relating these costs to utility operations.

Q. Would you please briefly explain the meaning of classification, functionalization, and allocation?

A. Classification groups costs into three categories: demand-related, energy-related, and customer-related.

In addition to classification, costs are functionalized; that is, costs are identified with utility operating functions such as generation, transmission, and distribution. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions. Once the Company's total system costs are classified and assigned to the appropriate function, they are allocated among jurisdictions.

The process of allocation is one of apportioning the total system cost among jurisdictions by introducing allocation factors into the process. An allocation factor is an array of numbers that specifies the jurisdictional value as a share or percent of the total system quantity. For example, in the case of energy-related costs, the allocation factor is annual jurisdictional energy use, adjusted for losses, divided by the total system energy use.

Once individual accounts have been allocated to the various jurisdictions, it is possible to summarize these into total utility rate base and net income by jurisdiction. The results are stated in a summary form to measure adequacy of revenues for the jurisdiction under consideration. The measure of adequacy is typically the rate of return earned on rate base, which is compared to the requested rate of return.

Q. Is the methodology used to separate costs by jurisdiction and calculate the Oregon jurisdictional revenue requirement in the present case primarily the same methodology utilized in the Company's last general rate case, Docket No. UE 213?

A. While the allocation methodology is primarily the same as in the Company's last general rate case, Docket No. UE 213, there are some proposed modifications in this filing. The primary change in methodology addresses how the Company proposes to allocate FERC Firm Transfer customers' transmission and distribution investments and related revenues and expenses.

Q. Why have you included this change in methodology in regards to the FERC Firm Transfer customers?

A. This change in methodology is the direct result of research by the Company's FERC & Regional Regulatory Affairs group in conjunction with Mr. Tatum as well as other members of the Regulatory Affairs group. The proposed methodology was reviewed and approved by the Company's Senior Management for use in the 2011 Test Year.

Q. Please describe the proposed change in methodology to the allocation of the Company's FERC Firm Transfer jurisdiction.

A. Under the Company's traditional jurisdictional allocation methodology, allocations assumed that each jurisdiction's transmission and distribution responsibility was proportional to the demand that each jurisdiction placed on the Company's system. The identical allocation methodology was applied uniformly by the Company for both its retail and Firm Transfer customers.

In 2006, the Company was authorized by the FERC to implement a formula rate for transmission service provided under its Open Access Transmission Tariff ("OATT"). It should be noted that Idaho Power Company itself is the Company's largest transmission customer because its retail customers are subject to the OATT formula rates as authorized by FERC when the Company buys and sells on behalf of its retail customers.

The FERC's OATT formula rate calculation does not synchronize with the Company's currently approved allocation methodology in significant ways. Under the formula rate, FERC prescribes defined classifications of plant and expenses authorized for functionalization as transmission and thereby billable to its Firm Transfer customers under the rates of the Company's OATT. This FERC-specific functionalization of transmission plant and expenses departs from the Company's current JSS model in the following areas:

- The OATT rate does not allow for inclusion of any distribution facilities or expenses and therefore, allocation of distribution-related costs to the company's Firm Transfer customers should be removed from the retail ratemaking model.

- The OATT rate specifically excludes Load Dispatching Expenses so they should not be allocated to Firm Transfer customers in the retail ratemaking model.
- The OATT rate specifically excludes generator step-up stations and generator interconnection facilities so they should not be allocated to Firm Transfer customers in the retail ratemaking model.

The OATT rate formula's divergence from the Company's currently approved rate making methodology manifests itself in a host of ways creating many opportunities for double-counting or exclusions if attempting to harmonize the two differing methodologies into a single allocation method. Therefore, the Company is proposing to change JSS methodology to allocate all Firm Transfer investments, expenses and revenues to the retail jurisdictions, in a manner similar to how the other two public utilities providing service in Oregon (Pacific Power – Order No. 05-021 and Portland General Electric – Docket No. UE 215) handle FERC-related costs and revenues as well as align the Oregon JSS with what the Company filed in Idaho (Case No. IPC-E-11-08).

Q. Besides the FERC Firm Transfer-related allocation changes, is the Company proposing any other methodology modifications?

A. Yes. Since the last general rate case, the Company has evaluated its allocation of tax-related rate base and expense line items. In each instance, the Company has sought to more properly align the tax item's allocation with its causation or fundamental association. For example, Account 190 - Accumulated Deferred Income Taxes has formerly been allocated over the Company's "Total Plant" investment. However, upon examination, revisions in this filing are made to allocate portions of Account 190 over "DA252 – Customer Advances for Construction" and "Labor" to more closely align allocations with the primary components within the account. Another example is "Idaho Energy Resources Company ("IERCO") Taxable Income" which is no longer being allocated by "State Taxable Income" but rather allocated in this filing over the Company's energy allocator in order to be consistent with the allocation of IERCO rate base investment and related income.

In summary, each tax-related line item in the JSS for this filing has been evaluated to determine the most appropriate allocation based on causation or fundamental association to the Company's investments or other underlying foundation. A comprehensive list of all the tax-related changes is included in my workpapers.

Q. How have the various functional plant and cost items been allocated?

A. The average of the 12 monthly coincident peak demands was used to allocate the demand-related costs. This allocation method has been used by the Company for at least two decades in all of its filings requiring a jurisdictional separation study. This allocation method was adopted by this Commission and also accepted by the Idaho Public Utilities Commission. The demand-related allocation factors used in the study are designated as D10, D11, D12, and D60. The respective values used in these demand allocation factors are shown at line numbers 1029 through 1032 of Exhibit 905.

Q. How were the energy-related expenses allocated among jurisdictions?

A. Energy-related expenses were allocated based on normalized jurisdictional kilowatt-hour sales and adjusted for losses to establish energy requirements at the generation level. The energy-related allocation factors used in the study are designated as E10 and E99. The respective values used in these energy allocation factors are shown on lines 1035 and 1036 of Exhibit 905.

Q. What was the method by which you allocated customer-related costs?

A. The principal customer-related expenses which required allocation were meter reading (FERC Account 902) and customer accounting and billing (FERC Account 903). These accounts were allocated based upon a review of actual Company practice of reading meters and preparing monthly bills or statements.

Q. What method was used to allocate certain labor-related administrative and general expenses?

A. In accordance with FERC-approved procedures, administrative and general expenses were allocated in accordance with functionalized wages and salaries. These labor-related allocation factors are shown on lines 829 through 1025 of Exhibit 905.

Q. Please describe the derivation of the 2011 total system allocation factors used in this case.

A. The allocation factors in the 2011 JSS were based on either the 2010 year-end data or 2011 assumptions. The capacity or demand–related allocation factors (D10, D11, D12, and D60) were created using the 2010 demand ratios from the load research sample applied to the 2011 Test Year energy. The energy-related allocation factors were the 2011 Test Year load at generation level (E10) and at customer level (E99).

Q. Briefly describe the manner in which you allocated electric plant in service as shown in Table 1 of Exhibit 905.

A. Production plant was allocated to all jurisdictions based on the average of the 12 monthly coincident peaks. Unless otherwise noted, allocation of transmission and distribution plant was based on the same methodology.

Q. Would you describe the functional categories used for allocation and direct assignment of transmission plant and distribution substations?

A. "Transmission facilities" are the facilities that form the bulk of the power transmission system together with transmission, step-up substation facilities required to introduce the Company's generation into the power supply system, and include facilities rated at 500 kilovolts ("kV") through 100 kV. "Distribution facilities" refer to lower voltage lines and the substation facilities that provide localized service. Some transmission and distribution facilities were directly assigned to the customers who paid for the exclusive use of those facilities. As previously discussed in this testimony, there are some proposed modifications to the direct assignment and allocation of FERC Network Service-related investments in this filing.

Q. Please describe the manner in which you allocated general electric plant in service.

A. General Plant was allocated on the same basis as the sum of the allocated investments in production, transmission, and distribution plant.

Q. How have you allocated the accumulated provision for depreciation and amortization of other utility plant?

A. Accumulated Provision for Depreciation was allocated among jurisdictions as shown on Table 2 of Exhibit 905. The accumulated totals for each type of production plant and for each primary plant account in other functional groups were allocated based on the related plant account as allocated in Table 1. Amortization of other utility plant was functionalized and then allocated based on the related plant items as allocated in Table 1.

Q. Please describe Table 3 of Exhibit 905.

A. Table 3 details the allocation of all other additions to or deductions from rate base. Deductions from rate base include customer advances for construction that were directly assigned to customers by jurisdiction, and the accumulated deferred income taxes that were allocated by plant, customer advances for construction, and labor.

Additions to rate base include: (1) materials and supplies which were functionalized and allocated by the respective plant allocators, (2) fuel inventory that was allocated on the basis of energy, (3) components of IERCO, the Company's fuel subsidiary, which were allocated based on energy, and (4) Commission-ordered deferred investment was either directly assigned to a specific jurisdiction or allocated based on energy.

All rate base items, with the exception of accumulated deferred income taxes and other deferred programs, reflect a 13-month average of ending balances.

Q. Please describe Table 4 of Exhibit 905.

A. Table 4 contains the adjusted firm operating revenues directly assigned to each jurisdiction for the test year (12 months ending December 31, 2011). Contractual Hoku first block energy sales revenues are allocated to each jurisdiction in proportion to generation-level energy usage. Opportunity sales, non-firm energy sales to other utilities, are also credited to each jurisdiction in proportion to generation-level energy use.

Other operating revenues were either allocated among jurisdictions in a manner that offset related allocations of rate base or, where a particular revenue item could be associated with a specific jurisdiction, directly assigned.

Q. Briefly describe the methods by which Operation and Maintenance Expenses were allocated.

A. The allocation of each O&M expense is detailed on Table 5 of Exhibit 905. In general, the basis for each allocation is identifiable with the source code listed on Exhibit 905. Demands are identified by a source code beginning with a "D" prefix, energy use is identified by a source code beginning with an "E" prefix, related plant is identified by a line number source code, and customer-weighted allocation factors begin with a "CW" prefix.

Q. In what manner are supervision and engineering expenses treated throughout the allocation of Operation and Maintenance Expenses?

A. For the applicable expense account in each functional group, the labor component was separately allocated in accordance with the detail provided on Table 13 of Exhibit 905. The total of allocated labor in each functional group became the basis for the allocation of supervision and engineering expense. Total allocated labor expense served the additional purpose of allocating employee pension and other labor-related taxes and expenses. Table 13 of Exhibit 905 details the development of all the labor-related allocation factors used in this study.

Q. Please describe Table 6 of Exhibit 905.

A. The allocation of depreciation expense and amortization of limited term plant is set forth on Table 6. These expenses were identified by type of production plant or by primary plant account for other functional plant groups and allocated consistent with the related plant account.

Q. Please describe Table 7 of Exhibit 905 and the allocation of Taxes Other Than Income Taxes.

A. Taxes Other Than Income Taxes were treated individually and allocated in a manner consistent with the bases by which the respective taxes are assessed.

Q. Please describe Table 8 of Exhibit 905.

A. Table 8 of Exhibit 905 details the amortization of regulatory debits and credits.

Q. Please describe Table 9 of Exhibit 905.

A. The expenses shown on Table 9 consist of deferred income taxes and the investment tax credit adjustments which were allocated based on the Company's plant investment and net income before tax adjustments. State and federal income tax liabilities are also summarized on Table 9. The income taxes shown on Tables 10 through 12 were obtained from the Company's Tax Department.

Q. Please describe how you allocated federal and state income taxes shown on Tables 10 through 12 of Exhibit 905.

A. The respective tax bases were developed, and taxes were calculated directly for each jurisdiction. Operating income before taxes represents adjusted operating revenues less all adjusted operating expenses treated heretofore with the exception of deferred income taxes and investment tax credits. Adjusted interest expense was allocated by the combined rate base to develop net operating income before taxes. As discussed earlier in this testimony, subsequent additions to or deductions from the respective tax bases were allocated to each jurisdiction by aligning it with its causation or fundamental association. In this manner, taxable income for each jurisdiction was developed and the appropriate tax rate was applied. Final tax amounts result after the allocation of adjustments and tax credits. All details relating to the calculation of federal, Oregon, Idaho, and other state income taxes are found on Tables 10, 11, and 12.

Q. Please describe Tables 13 through 15 of Exhibit 905.

A. Tables 13 through 15 of Exhibit 905 list the principal allocation factors used in the JSS and the respective jurisdictional values for each allocation factor. Table 15 lists the ratios of the principal allocation factors included in Table 14.

Q. Please describe the development of the Oregon jurisdictional revenue deficiency.

A. The summary of JSS results is presented on pages 1 and 2 of Exhibit 905. The development of the Oregon jurisdictional revenue deficiency is presented in the column entitled “Oregon Retail” on page 1 of Exhibit 905. The Oregon consolidated operating income of $6,394,048 (line 27) resulted in a return on rate base of 5.25 percent (line 28). Based upon the Company’s request for an overall rate of return of 10.5 percent provided by Mr. Steve Keen, the Company’s Oregon jurisdictional net income should be $9,955,453, as shown on line 33. The resulting earnings deficiency is $3,561,404, as shown on line 34.

Q. What net-to-gross or incremental income tax factor did you use in developing the Oregon jurisdictional revenue deficiency?

A. The composite incremental tax multiplier of 1.642 is the assimilation of the federal effective tax rate, an Idaho composite tax rate, an Oregon composite tax rate, and an additional state composite tax rate. This value, as shown on line 38 of Exhibit 905, was provided by the Company's Tax Department and is included in my workpapers.

Q. What is the resulting Oregon jurisdictional revenue deficiency?

A. The result of the Jurisdictional Separation Study, as shown on page 1, line 39 of Exhibit 905, indicates a total revenue deficiency of $5.8 million for the Oregon retail jurisdiction. This represents a required 14.67 percent increase in normalized Oregon jurisdictional revenues.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Kelley Noe
Major Plant Additions Annualized for 2011

July 29, 2011

Idaho Power Company
Major Plant Additions Annualized for 2011

Line No.	Project Type	Project ID	Description	In Service Date	(1) Annualized Plant	(2) Adjustment for Plant Est to Close 2011	(3) Net Annualizing Adjustments	(4) State	(5) Annual Composite Property Tax Rate	(6) Annual Composite Property Tax	(7) Annual Insurance Rate Per $100	(8) Annual Insurance Expense
	Transmission:											
	Stations:											
1	31	TFPR0901	Kimberly Lines and Stations	June, 2011	$ 51,321	$ 27,634	$ 23,687	ID	0.450%	$ 107	$ 0.0380	$ 9
2	31 Total				51,321	27,634	23,687			107		9
3	32	MPSN0802	Increase T342 to 700 MVA	June, 2011	4,179,604	2,250,556	1,929,048	ID	0.450%	8,681	$ 0.0380	733
4	32 Total				4,179,604	2,250,556	1,929,048			8,681		733
	Lines:											
5	33	T4660901	Victory Lines and Stations	November, 2011	1,757,039	270,314	1,486,725	ID	0.450%	6,690	$ 0.0380	565
6		T4520704	Kimberly Lines and Stations	June, 2011	1,148,666	618,512	530,154	ID	0.450%	2,386	$ 0.0380	201
7	33 Total				2,905,705	888,826	2,016,879			9,076		766
	Distribution:											
	Substations:											
8	41	VTRY0501	Victory Lines and Stations	November, 2011	2,153,531	331,312	1,822,219	ID	0.520%	9,476	$ 0.0380	692
9		KBLY0701	Kimberly Lines and Stations	June, 2011	2,050,581	1,104,159	946,422	ID	0.520%	4,921	$ 0.0380	360
10		BKFT1001	Replace Metalclad Switchgear Sections 1 & 2	June, 2011	2,643,335	1,423,334	1,220,001	ID	0.520%	6,344	$ 0.0380	464
11		B00809330	AMI Communications Equipment Purchases & Installation	January, 2011	1,036,848	957,090	79,758	ID	0.520%	415	$ 0.0380	30
12		B00809330	AMI Communications Equipment Purchases & Installation	February, 2011	841,947	712,417	129,530	ID	0.520%	674	$ 0.0380	49
13		B00809330	AMI Communications Equipment Purchases & Installation	March, 2011	729,905	561,466	168,440	ID	0.520%	876	$ 0.0380	64
14		B00809330	AMI Communications Equipment Purchases & Installation	April, 2011	764,002	528,925	235,078	ID	0.520%	1,222	$ 0.0380	89
15		B00809330	AMI Communications Equipment Purchases & Installation	May, 2011	602,319	370,658	231,661	ID	0.520%	1,205	$ 0.0380	88
16		B00809330	AMI Communications Equipment Purchases & Installation	June, 2011	791,887	426,401	365,486	ID	0.520%	1,901	$ 0.0380	139
17		B00809330	AMI Communications Equipment Purchases & Installation	July, 2011	471,239	217,495	253,744	ID	0.520%	1,319	$ 0.0380	96
18		B00809330	AMI Communications Equipment Purchases & Installation	August, 2011	630,287	242,418	387,869	ID	0.520%	2,017	$ 0.0380	147
19		B00809330	AMI Communications Equipment Purchases & Installation	September, 2011	658,267	202,544	455,723	ID	0.520%	2,370	$ 0.0380	173
20		B00809330	AMI Communications Equipment Purchases & Installation	October, 2011	709,837	163,808	546,028	ID	0.520%	2,839	$ 0.0380	207
21		B00809330	AMI Communications Equipment Purchases & Installation	November, 2011	633,785	97,505	536,279	ID	0.520%	2,789	$ 0.0380	204
22		B00809330	AMI Communications Equipment Purchases & Installation	December, 2011	513,530	39,502	474,028	ID	0.520%	2,465	$ 0.0380	180
23	41 Total				15,231,300	7,379,034	7,852,266			40,832		2,984
	Lines:											
24	43	VTRY0601	Victory Lines and Stations	November, 2011	543,831	83,666	460,165	ID	0.520%	2,393	$ 0.0380	175
25		KBLY0702	Kimberly Lines and Stations	June, 2011	421,283	226,845	194,438	ID	0.520%	1,011	$ 0.0380	74
26		KBLY0703	Kimberly Lines and Stations	June, 2011	253,274	136,378	116,896	ID	0.520%	608	$ 0.0380	44
27	43 Total				1,218,388	446,889	771,499			4,012		293
	Meters;											
28	1	B00600021	AMI Meter Purchases & Installations	January, 2011	2,169,705	2,002,804	166,900	ID	0.520%	868	$ 0.0380	63
29		B00600021	AMI Meter Purchases & Installations	February, 2011	1,128,668	955,027	173,641	ID	0.520%	903	$ 0.0380	66
30		B00600021	AMI Meter Purchases & Installations	March, 2011	1,218,542	937,340	281,202	ID	0.520%	1,462	$ 0.0380	107
31		B00600021	AMI Meter Purchases & Installations	April, 2011	1,256,300	869,746	386,554	ID	0.520%	2,010	$ 0.0380	147
32		B00600021	AMI Meter Purchases & Installations	May, 2011	1,217,947	749,506	468,441	ID	0.520%	2,436	$ 0.0380	178
33		B00600021	AMI Meter Purchases & Installations	June, 2011	1,242,268	668,914	573,355	ID	0.520%	2,981	$ 0.0380	218
34		B00600021	AMI Meter Purchases & Installations	July, 2011	1,225,035	565,401	659,634	ID	0.520%	3,430	$ 0.0380	251
35		B00600021	AMI Meter Purchases & Installations	August, 2011	1,225,651	471,404	754,247	ID	0.520%	3,922	$ 0.0380	287
36		B00600021	AMI Meter Purchases & Installations	September, 2011	1,263,880	388,886	874,994	ID	0.520%	4,550	$ 0.0380	332
37		B00600021	AMI Meter Purchases & Installations	October, 2011	1,226,419	283,020	943,399	ID	0.520%	4,906	$ 0.0380	358
38		B00600021	AMI Meter Purchases & Installations	November, 2011	343,629	52,866	290,763	ID	0.520%	1,512	$ 0.0380	110
39		B00600021	AMI Meter Purchases & Installations	December, 2011	75,826	5,833	69,993	ID	0.520%	364	$ 0.0380	27
40	01 Total				13,593,870	7,950,746	5,643,123			29,344		2,144
41	Total Transmission and Distribution				37,180,188	18,943,687	18,236,501			92,051		6,930

Idaho Power Company
Major Plant Additions Annualized for 2011

Line No.	Project Type	Project ID	Description	In Service Date	(1) Annualized Plant	(2) Adjustment for Plant Est to Close 2011	(3) Net Annualizing Adjustments	(4) State	(5) Annual Composite Property Tax Rate	(6) Annual Composite Property Tax	(7) Annual Insurance Rate Per $100	(8) Annual Insurance Expense
	Power Supply:											
	Thermal:											
42	21	B00900447	JB U3 S02 & PM Em Cntrl Upgrades	July, 2008	8,244,022	3,804,933	4,439,089	WY	0.220%	9,766	$ 0.0380	1,687
43		B00900447	JB U3 S02 & PM Em Cntrl Upgrades	August, 2011	13,333	5,128	8,205	WY	0.220%	18	$ 0.0380	3
44		B00900447	JB U3 S02 & PM Em Cntrl Upgrades	September, 2011	5,000	1,538	3,462	WY	0.220%	8	$ 0.0380	1
45		B00900462	U3 Reheater Outlet Terminal Tubes 11	June, 2011	2,158,498	1,162,268	996,230	WY	0.220%	2,192	$ 0.0380	379
46		B01100153	V1 Reheat Tube, Replace	June, 2011	3,795,349	2,043,649	1,751,700	NV	0.320%	5,605	$ 0.0380	666
47		B01100153	V1 Reheat Tube, Replace	July, 2011	100,000	46,154	53,846	NV	0.320%	172	$ 0.0380	20
48		B01100153	V1 Reheat Tube, Replace	August, 2011	12,500	4,808	7,692	NV	0.320%	25	$ 0.0380	3
49		B01100153	V1 Reheat Tube, Replace	September, 2011	12,500	3,846	8,654	NV	0.320%	28	$ 0.0380	3
50		B01100153	V1 Reheat Tube, Replace	October, 2011	5,000	1,154	3,846	NV	0.320%	12	$ 0.0380	1
51		B01100153	V1 Reheat Tube, Replace	November, 2011	5,000	769	4,231	NV	0.320%	14	$ 0.0380	2
52		B01100153	V1 Reheat Tube, Replace	December, 2011	4,600	354	4,246	NV	0.320%	14	$ 0.0380	2
53		B00700252	V1 Cooling Tower, Replace	June, 2011	3,260,405	1,755,603	1,504,802	NV	0.320%	4,815	$ 0.0380	572
54		B00700252	V1 Cooling Tower, Replace	July, 2011	25,000	11,538	13,462	NV	0.320%	43	$ 0.0380	5
55		B00700252	V1 Cooling Tower, Replace	August, 2011	12,500	4,808	7,692	NV	0.320%	25	$ 0.0380	3
56		B00700252	V1 Cooling Tower, Replace	September, 2011	12,500	3,846	8,654	NV	0.320%	28	$ 0.0380	3
57		B00700252	V1 Cooling Tower, Replace	October, 2011	5,000	1,154	3,846	NV	0.320%	12	$ 0.0380	1
58		B00700252	V1 Cooling Tower, Replace	November, 2011	5,000	769	4,231	NV	0.320%	14	$ 0.0380	2
59		B00700252	V1 Cooling Tower, Replace	December, 2011	5,000	385	4,615	NV	0.320%	15	$ 0.0380	2
60		B01000235	VC Evaporator Pond Liner Upgrade, Pond A	September, 2011	2,530,657	778,664	1,751,993	NV	0.320%	5,606	$ 0.0380	666
61		B01000227	V1 Secondary Superheater Assembly, Replace	June, 2011	2,574,940	1,386,506	1,188,434	NV	0.320%	3,803	$ 0.0380	452
62		B01000227	V1 Secondary Superheater Assembly, Replace	July, 2011	75,000	34,615	40,385	NV	0.320%	129	$ 0.0380	15
63		B01000227	V1 Secondary Superheater Assembly, Replace	August, 2011	12,500	4,808	7,692	NV	0.320%	25	$ 0.0380	3
64		B01000227	V1 Secondary Superheater Assembly, Replace	September, 2011	12,500	3,846	8,654	NV	0.320%	28	$ 0.0380	3
65		B01000227	V1 Secondary Superheater Assembly, Replace	October, 2011	5,000	1,154	3,846	NV	0.320%	12	$ 0.0380	1
66		B01000227	V1 Secondary Superheater Assembly, Replace	November, 2011	5,000	769	4,231	NV	0.320%	14	$ 0.0380	2
67		B01000227	V1 Secondary Superheater Assembly, Replace	December, 2011	2,508	193	2,315	NV	0.320%	7	$ 0.0380	1
68	21 Total				22,899,311	11,063,259	11,836,052			32,428		4,498
69	Total Power Supply				22,899,311	11,063,259	11,836,052			32,428		4,498
	Corporate Administration Support:											
	General Land and Buildings:											
70	51	B001100069	Purchase of Land, Buildings and Remodeling Costs	March, 2011	6,098,209	4,690,930	1,407,279	ID	0.520%	7,318	$ 0.0380	535
71	51 Total				6,098,209	4,690,930	1,407,279			7,318		535
	General Office Furniture											
72	52	B01100073	Furniture	March, 2011	168,377	129,521	38,856	ID	0.520%	202	$ 0.0380	15
73	52 Total				168,377	129,521	38,856			202		15
	Data and Word Processing Equipment											
74	58	B01100074	IT Hardware, Software & Associated Remodeling Costs	March, 2011	350,000	269,231	80,769	ID	0.520%	420	$ 0.0380	31
75	58 Total				350,000	269,231	80,769			420		31
76	Total Corporate Administration Support:				6,616,586	5,089,682	1,526,905			7,940		580
77	Total				$ 66,696,085	$ 35,096,628	$ 31,599,458			$ 132,419		$ 12,008

Summary

	(1)	(2)	(3)	(4)	(5)
Kimberly Lines and Stations	$ 3,925,125	$ 2,113,529	$ 1,811,596	Reliability	0
Increase T342 to 700 MVA	4,179,604	2,250,556	1,929,048	Legal/Reg	0
Victory Lines and Stations	4,454,401	685,292	3,769,109	Reliability	0
Replace Metalclad Switchgear Sections 1 & 2	2,643,335	1,423,334	1,220,001	Reliability	0
AMI Communications Equipment Purchases & Installation	8,383,853	4,520,229	3,863,624	Legal/Reg	0
AMI Meter Purchases & Installations	13,593,870	7,950,746	5,643,123	Legal/Reg	0
JB U3 S02 & PM Em Cntrl Upgrades	8,262,355	3,811,600	4,450,755	Reliability	0
U3 Reheater Outlet Terminal Tubes 11	2,158,498	1,162,268	996,230	Reliability	0
V1 Reheat Tube, Replace	3,934,949	2,100,734	1,834,215	Reliability	0
V1 Cooling Tower, Replace	3,325,405	1,778,103	1,547,302	Reliability	0
VC Evaporator Pond Liner Upgrade, Pond A	2,530,657	778,664	1,751,993	Reliability	0
V1 Secondary Superheater Assembly, Replace	2,687,448	1,431,891	1,255,557	Reliability	0
Purchase of Land, Buildings and Remodeling Costs	6,616,586	5,089,682	1,526,905	Reliability	0
Total	$ 66,696,085	$ 35,096,628	$ 31,599,458		

Purpose:
- Load Growth
- Legal
- Regulatory

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Kelley Noe
Depreciation and Amortization Annualizing Adjustments

July 29, 2011

Idaho Power Company
Depreciation & Amortization Annualizing Adjustments
Estimated 2011

Account	Account Description	Annualized Depreciation Expense	Forecasted Depreciation Expense	Annualizing Adjustment	Reserve Adjustment
30100	Organization				
30200	Franchises and Consents	853,176.48	853,176.48	-	-
30300	Miscellaneous Intangible Plant	6,378,354.24	6,188,898.97	189,455.27	94,727.63
TOTAL INTANGIBLE PLANT- AMORT		7,231,530.72	7,042,075.45	189,455.27	94,727.63
31020	Land and Land Rights	8,268.36	8,268.36	-	-
31100	Structures and Improvements	2,152,401.96	2,144,648.26	7,753.70	3,876.85
31200	Boiler Plant Equipment	11,830,485.84	11,639,056.43	191,429.41	95,714.71
31400	Turbogenerator Units	3,891,755.76	3,826,824.57	64,931.19	32,465.59
31500	Accessory electric Equipment	809,497.68	810,840.18	(1,342.50)	(671.25)
31600	Misc Power Plant Equipment	506,930.28	505,200.23	1,730.05	865.02
TOTAL STEAM PRODUCTION PLANT		19,199,339.88	18,934,838.03	264,501.85	132,250.92
33000	Land and Land Rights			-	-
33100	Structures and Improvements	4,098,214.44	4,070,470.91	27,743.53	13,871.76
33200	Reservoirs, Dams, Waterways	5,652,985.56	5,638,735.96	14,249.60	7,124.80
33300	Waterwheel, Turbines, Generato	3,698,414.28	3,690,360.72	8,053.56	4,026.78
33400	Accessory Electric Equipment	1,340,542.20	1,328,437.51	12,104.69	6,052.35
33500	Misc Power Plant Equipment	492,998.88	482,276.90	10,721.98	5,360.99
33600	Roads, Railroads and Bridges	145,321.08	145,321.08	-	-
TOTAL HYDRO PRODUCTION PLANT		15,428,476.44	15,355,603.08	72,873.36	36,436.68
34000	LAND AND LAND RIGHTS				
34100	Structures and Improvements	221,232.60	220,768.69	463.91	231.95
34200	Fuel Holders, Producers, Acces	121,639.20	121,387.15	252.05	126.03
34300	Prime Movers	3,267,119.28	3,260,866.96	6,252.32	3,126.16
34400	Generators	946,997.52	945,040.88	1,956.64	978.32
34500	Accessory Electric Equipment	808,401.96	806,742.67	1,659.29	829.65
34600	Misc Power Plant Equipment	78,931.80	78,770.33	161.47	80.73
TOTAL OTHER PRODUCTION PLANT		5,444,322.36	5,433,576.68	10,745.68	5,372.84
35020	Land and Land Rights	455,047.20	455,047.20 *	-	-
35200	Structures and Improvements	954,983.40	946,120.72	8,862.68	4,431.34
35300	Station Equipment	7,369,784.28	7,299,358.34	70,425.94	35,212.97
35400	Towers and Fixtures	2,940,288.36	2,878,883.18	61,405.18	30,702.59
35500	Poles and Fixtures	2,899,667.28	2,873,489.03	26,178.25	13,089.13
35600	Overhead Conductors, Devices	3,322,211.40	3,280,317.70	41,893.70	20,946.85
35900	Roads and Trails	3,132.60	3,132.60	-	-
TOTAL TRANSMISSION PLANT		17,945,114.52	17,736,348.77	208,765.75	104,382.88
36000	Land and Land Rights				
36100	Structures and improvements	593,227.56	566,603.00	26,624.56	13,312.28
36200	Station Equipment	3,664,705.92	3,552,727.22	111,978.70	55,989.35
TOTAL SUBSTATION EQUIPMENT		4,257,933.48	4,119,330.22	138,603.26	69,301.63
36400	Poles, Towers and Fixtures	7,653,064.92	7,521,720.04	131,344.88	65,672.44
36500	Overhead Conductors, Devices	3,677,442.12	3,608,869.64	68,572.48	34,286.24
36600	Underground Conduit	982,581.24	963,045.13	19,536.11	9,768.05
36700	Underground Conductors, Device	3,909,246.84	3,839,295.32	69,951.52	34,975.76
36800	Line Transformers	7,106,084.88	7,012,924.70	93,160.18	46,580.09
36900	Services	1,829,475.24	1,803,191.83	26,283.41	13,141.70
37000	Meters	1,024,934.76	1,029,540.33	(4,605.57)	(2,302.79)
37010	Meters - AMI	3,677,844.60	3,226,727.28	451,117.32	225,558.66
37030	Meters-Non AMI - Idaho	10,551,353.52	10,551,353.52		
37100	Installations, Cust Premises	29,256.24	28,967.40	288.84	144.42
37300	Street Lighting, Signal System	179,432.76	179,067.89	364.87	182.43
TOTAL DISTRIBUTION LINES		40,620,717.12	39,764,703.08	856,014.04	428,007.00
38900	Land and Land Rights				
39000	Structures and Improvements	1,954,946.04	1,898,283.28	56,662.76	28,331.38
39100	Office Furniture, Equipment	7,851,477.00	7,417,941.94	433,535.06	216,767.53
39200	Transportation Equipment	2,219,319.00	2,224,286.19		3,097.09
39300	Stores Equipment	85,303.92	81,344.93	3,958.99	1,979.50
39400	Tools, Shop, Garage Equipment	283,465.32	276,174.82	7,290.50	3,645.25
39500	Laboratory Equipment	684,507.60	664,858.21	19,649.39	9,824.70
39600	Power Operated Equipment	676,137.60	681,232.72		10,005.41
39700	Communication Equipment	2,308,200.24	2,177,302.13	130,898.11	65,449.05
39800	Miscellaneous Equipment	505,034.16	483,371.42	21,662.74	10,831.37
TOTAL GENERAL EQUIPMENT PLANT		16,568,390.88	15,904,795.64	673,657.55	349,931.28
DEPR ON ELECTRIC PLANT IN SERVICE		119,464,294.68	117,249,195.50	2,225,161.49	1,125,683.23
	Amortization of Disallowed Costs	(296,299.32)	(296,299.32)	-	-
TOTAL DEPRECIATION & AMORTIZATION		126,399,526.08	123,994,971.63	2,414,616.76	1,220,410.86
	Account 312.300	(108,264.72)	(108,264.72)		
	Account 392	(1,996,903.08)	(2,001,870.27)		
	Account 396	(676,137.60)	(681,232.72)		
	Account 397.3.00	(272,780.88)	(272,780.88)		
	Account 403 and 404	123,345,439.80	120,930,823.04		

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Kelley Noe
Summary of Payroll-Related Annualizing Adjustments

July 29, 2011

Idaho Power Company
Summary of Payroll-Related Annualizing Adjustments
Operating Expenses

Line No.	Source Page		(1) Amount
1	A	Operating Payroll - Annualizing Adjustment	$ 1,955,023
2	A	2012 Salary Structure Adjustment	2,377,859
3		**Total Adjustments**	$4,332,883

A

Idaho Power Company
Detail of Adjustments to 2011
Operating Expenses

Line No.	Source Page				(1) Amount
		1) Operating Payroll (Various accts)			
1	1	Actual Total Year 2010 ST Payroll			148,290,903
2	1	Actual December 2010 ST Payroll	11,597,700		
3		Annualized December 2010 (Dec times 13)	x 13		150,770,100
4		Increase Over 2010 Actual			2,479,197
5	1	O&M Percentage			56.94%
6		Annualized December 2010 O&M ST payroll			1,411,696
7	2	Benefit Loading Percent			38.49%
8		Annualized December 2010 O&M ST w/Loading		$	1,955,023
		2) 2012 Operating Payroll SSA (Various accts)			
9	A	Annualized December 2011 ST Payroll		$	150,770,100
10		2012 Structured Salary Adjustment	2.00%		3,015,402
11	1	O&M Percentage			56.94%
12		O&M Wages Subject to Benefit Loading			1,717,020
13	2	Benefit Loading Percent			38.49%
14		Adjustment to Operating Expense		$	2,377,859

2010 ACTUAL for 111 - STRAIGHT TIME PAYROLL
By Account and Month

Source Page 1

	1 - O&M	2 - Construction	3 - Other	242 Accounts	Total
Jan,10	5,975,138	2,317,295	619,235	2,336,499	11,248,167
Feb,10	6,886,441	2,456,548	674,713	1,247,658	11,265,360
Mar,10	6,993,988	2,668,028	783,769	873,689	11,319,474
Apr,10	10,240,878	4,085,596	1,158,527	1,549,690	17,034,691
May,10	6,740,251	2,860,903	759,472	969,453	11,330,080
Jun,10	6,378,187	2,476,442	750,529	1,748,816	11,353,974
Jul,10	6,142,794	2,626,590	714,893	1,934,182	11,418,459
Aug,10	6,449,934	2,827,369	743,320	1,425,098	11,445,720
Sep,10	6,341,582	2,757,785	689,240	1,683,077	11,471,683
Oct,10	10,076,022	4,411,723	1,119,403	1,641,380	17,248,527
Nov,10	5,898,392	2,566,563	659,597	2,432,516	11,557,068
Dec,10	6,315,709	2,918,480	741,521	1,621,990	**11,597,700**
	84,439,315	34,973,323	9,414,219	19,464,046	**148,290,903**
% of Total	**56.94%**	23.58%	6.35%	13.13%	100.00%

Annualized December (x 13)	150,770,100
Annualized Payroll Growth Factor	**1.67%**

2010 Actual Benefits Loading %

Source Page 2

	Feb-11	
111 - STRAIGHT TIME PAYROLL	7,131,983	
131 - INDIRECT BENEFIT LOAD	2,068,045	29.00%
140 - TAXES-EMPLOYER PAID	676,882	9.49%
Subtotal loading	**2,744,926**	**38.49%**

Idaho Power/904
Witness: Kelley Noe

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Kelley Noe
Development of System Revenue Requirement

July 29, 2011

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
4	***SUMMARY OF RESULTS***							
5	**RATE OF RETURN UNDER PRESENT RATES**							
6	TOTAL COMBINED RATE BASE	2,420,460,776	(26,225,097)	2,394,235,679	74,508,379	2,468,744,058	30,552,843	2,499,296,901
7								
8	OPERATING REVENUES							
9	FIRM JURISDICTIONAL SALES	873,185,400	(51,699,214)	821,486,186	30,553,596	852,039,782	0	852,039,782
10	HOKU 1ST BLOCK ENERGY SALES	27,572	0	27,572	23,953,827	23,981,399	0	23,981,399
11	SYSTEM OPPORTUNITY SALES	75,248,792	(2,518,092)	72,730,700	10,146,056	82,876,756	0	82,876,756
12	OTHER OPERATING REVENUES	84,590,356	(41,612,875)	42,977,481	1,577,757	44,555,238	0	44,555,238
13	TOTAL OPERATING REVENUES	1,033,052,120	(95,830,181)	937,221,939	66,231,236	1,003,453,175	0	1,003,453,175
14	OPERATING EXPENSES							
15	OPERATION & MAINTENANCE EXPENSES	693,221,251	(92,692,588)	600,528,663	79,892,687	680,421,350	4,344,891	684,766,241
16	DEPRECIATION EXPENSE	109,099,197	0	109,099,197	4,789,543	113,888,740	2,225,161	116,113,901
17	AMORTIZATION OF LIMITED TERM PLANT	6,355,759	478,819	6,834,578	184,774	7,019,352	189,455	7,208,808
18	TAXES OTHER THAN INCOME	24,046,036	0	24,046,036	3,454,070	27,500,107	132,419	27,632,526
19	REGULATORY DEBITS/CREDITS	21,955	0	21,955	5,802	27,757	0	27,757
20	PROVISION FOR DEFERRED INCOME TAXES	2,396,127	0	2,396,127	37,180,330	39,576,457	0	39,576,457
21	INVESTMENT TAX CREDIT ADJUSTMENT	(1,533,190)	0	(1,533,190)	(1,062,201)	(470,989)	0	(470,989)
22	FEDERAL INCOME TAXES	5,967,392	(12,896,763)	(6,929,371)	723,279	(4,663,905)	(2,260,207)	(6,924,112)
23	STATE INCOME TAXES	3,057,226	(1,934,592)	1,122,634	1,581,589	2,704,222	(434,191)	2,270,031
24	TOTAL OPERATING EXPENSES	842,631,755	(107,045,125)	735,586,630	126,749,873	866,003,091	4,197,528	870,200,619
25	OPERATING INCOME	190,420,365	11,214,944	201,635,309	(60,518,637)	137,450,084	(4,197,528)	133,252,556
26	ADD: IERCO OPERATING INCOME	7,575,497	0	7,575,497	(945,499)	6,629,998	0	6,629,998
27	CONSOLIDATED OPERATING INCOME	197,995,862	11,214,944	209,210,806	(61,464,136)	144,080,082	(4,197,528)	139,882,554
28	RATE OF RETURN UNDER PRESENT RATES	8.18%		8.74%				5.60%
29								
30	**DEVELOPMENT OF REVENUE REQUIREMENTS**							
31	RATE OF RETURN @ 10.5% ROE	8.170%	8.170%	8.170%	8.170%	8.170%	8.170%	8.170%
32								
33	RETURN	197,751,645	(2,142,590)	195,609,055	6,087,335	201,696,390	2,496,167	204,192,557
34	EARNINGS DEFICIENCY	(244,217)	(13,357,534)	(13,601,751)	67,551,470	57,616,308	6,693,695	64,310,003
35	ADD: CWIP (RELICENSING)	0	0	0	0	0	0	0
36	DEFICIENCY WITH CWIP	(244,217)	(13,357,534)	(13,601,751)	67,551,470	57,616,308	6,693,695	64,310,003
37								
38	NET-TO-GROSS TAX MULTIPLIER	1.642	1.642	1.642	1.642	1.642	1.642	1.642
39	**REVENUE DEFICIENCY**	(401,004)	(21,933,071)	(22,334,075)	110,919,514	94,605,977	10,991,047	105,597,024
40								
41	FIRM JURISDICTIONAL REVENUES	877,267,880	(51,699,214)	825,568,666	55,246,703	876,021,181	0	876,021,181
42	PERCENT INCREASE REQUIRED	-0.05%		-2.71%		10.80%		12.05%
43								0
44	SALES AND WHEELING REVENUES REQUIRED	876,866,876	(73,632,285)	803,234,591	166,166,217	970,627,158	10,991,047	981,618,205

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
45	***SUMMARY OF RESULTS***							
46	**DEVELOPMENT OF RATE BASE COMPONENTS**							
47	ELECTRIC PLANT IN SERVICE							
48	INTANGIBLE PLANT	53,059,662	0	53,059,662	1,461,012	54,520,675	0	54,520,675
49	PRODUCTION PLANT	1,772,638,416	0	1,772,638,416	31,557,028	1,804,195,444	11,836,052	1,816,031,496
50	TRANSMISSION PLANT	803,602,485	0	803,602,485	62,200,462	865,802,947	3,969,614	869,772,561
51	DISTRIBUTION PLANT	1,352,499,478	0	1,352,499,478	58,055,898	1,410,555,376	14,266,888	1,424,822,264
52	GENERAL PLANT	249,569,354	0	249,569,354	12,597,790	262,167,144	1,526,904	263,694,048
53	TOTAL ELECTRIC PLANT IN SERVICE	4,231,369,395	0	4,231,369,395	165,872,190	4,397,241,585	31,599,458	4,428,841,043
54	LESS: ACCUM PROVISION FOR DEPRECIATION	1,724,538,162	0	1,724,538,162	63,737,756	1,788,275,918	1,125,683	1,789,401,601
55	AMORT OF OTHER UTILITY PLANT	18,391,104	0	18,391,104	2,820,040	21,211,144	94,728	21,305,872
56	NET ELECTRIC PLANT IN SERVICE	2,488,440,130	0	2,488,440,130	99,314,393	2,587,754,523	30,379,047	2,618,133,570
57	LESS: CUSTOMER ADV FOR CONSTRUCTION	23,565,979	0	23,565,979	(6,304,446)	17,261,533	0	17,261,533
58	LESS: ACCUM DEFERRED INCOME TAXES	255,421,806	0	255,421,806	36,614,241	292,036,047	0	292,036,047
59	ADD : PLT HLD FOR FUTURE+ACQUIS ADJ	7,076,146	(7,112,123)	(35,977)	22,723	(13,254)	0	(13,254)
60	ADD : WORKING CAPITAL	112,848,202	(19,027,444)	93,820,759	5,180,347	99,001,106	173,796	99,174,902
61	ADD : CONSERVATION+OTHER DFRD PROG.	2,156,839	0	2,156,839	146,580	2,303,419	0	2,303,419
62	ADD : SUBSIDIARY RATE BASE	88,927,245	(85,531)	88,841,714	154,130	88,995,844	0	88,995,844
63	TOTAL COMBINED RATE BASE	2,420,460,776	(26,225,097)	2,394,235,679	74,508,379	2,468,744,058	30,552,843	2,499,296,901
64								
65	**DEVELOPMENT OF NET INCOME COMPONENTS**							
66	OPERATING REVENUES							
67	SALES REVENUES	948,461,764	(54,217,306)	894,244,458	64,653,479	958,897,937	0	958,897,937
68	OTHER OPERATING REVENUES	84,590,356	(41,612,875)	42,977,481	1,577,757	44,555,238	0	44,555,238
69	TOTAL OPERATING REVENUES	1,033,052,120	(95,830,181)	937,221,939	66,231,236	1,003,453,175	0	1,003,453,175
70	OPERATING EXPENSES			0				
71	OPERATION & MAINTENANCE EXPENSES	693,221,251	(92,692,588)	600,528,663	79,892,687	680,421,350	4,344,891	684,766,241
72	DEPRECIATION EXPENSE	109,099,197	0	109,099,197	4,789,543	113,888,740	2,225,161	116,113,901
73	AMORTIZATION OF LIMITED TERM PLANT	6,355,759	478,819	6,834,578	184,774	7,019,352	189,455	7,208,808
74	TAXES OTHER THAN INCOME	24,046,036	0	24,046,036	3,454,070	27,500,107	132,419	27,632,526
75	REGULATORY DEBITS/CREDITS	21,955	0	21,955	5,802	27,757	0	27,757
76	PROVISION FOR DEFERRED INCOME TAXES	2,396,127	0	2,396,127	37,180,330	39,576,457	0	39,576,457
77	INVESTMENT TAX CREDIT ADJUSTMENT	(1,533,190)	0	(1,533,190)	(1,062,201)	(470,989)	0	(470,989)
78	FEDERAL INCOME TAXES	5,967,392	(12,896,763)	(6,929,371)	723,279	(4,663,905)	(2,260,207)	(6,924,112)
79	STATE INCOME TAXES	3,057,226	(1,934,592)	1,122,634	1,581,589	2,704,222	(434,191)	2,270,031
80	TOTAL OPERATING EXPENSES	842,631,755	(107,045,125)	735,586,630	126,749,873	866,003,091	4,197,528	870,200,619
81	OPERATING INCOME	190,420,365	11,214,944	201,635,309	(60,518,637)	137,450,084	(4,197,528)	133,252,556
82	ADD: IERCO OPERATING INCOME	7,575,497	0	7,575,497	(945,499)	6,629,998	0	6,629,998
83	CONSOLIDATED OPERATING INCOME	197,995,862	11,214,944	209,210,806	(61,464,136)	144,080,082	(4,197,528)	139,882,554
84								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
107	***TABLE 1-ELECTRIC PLANT IN SERVICE***							
108	INTANGIBLE PLANT							
109	301 - ORGANIZATION	$ (2,252)		(2,252)	7,955	5,703	0	5,703
110	302 - FRANCHISES & CONSENTS	22,744,494		22,744,494	655,660	23,400,154	0	23,400,154
111	303 - MISCELLANEOUS	30,317,420		30,317,420	797,397	31,114,818	0	31,114,818
112								
113	TOTAL INTANGIBLE PLANT	53,059,662		53,059,662	1,461,012	54,520,675	0	54,520,675
114								
115	PRODUCTION PLANT							
116	310-316 / STEAM PRODUCTION	901,321,993		901,321,993	24,798,040	926,120,033	11,836,052	937,956,085
117	330-336 / HYDRAULIC PRODUCTION	697,307,358		697,307,358	5,503,086	702,810,444	0	702,810,444
118	340-346 / OTHER PRODUCTION	174,009,064		174,009,064	1,255,902	175,264,966	0	175,264,966
119								
120	TOTAL PRODUCTION PLANT	1,772,638,416		1,772,638,416	31,557,028	1,804,195,444	11,836,052	1,816,031,496
121								
122	TRANSMISSION PLANT							
123	350 / LAND & LAND RIGHTS - SYSTEM SERVICE	32,831,106		32,831,106	1,297,033	34,128,139	0	34,128,139
124	TRANSMISSION RETAIL	125,006		125,006	0	125,006	0	125,006
125	DIRECT ASSIGNMENT	792		792	0	792	0	792
126	TOTAL ACCOUNT 350	32,956,904		32,956,904	1,297,033	34,253,937	0	34,253,937
127								
128	352 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	45,400,962		45,400,962	9,282,506	54,683,468	0	54,683,468
129	TRANSMISSION RETAIL	1,681,193		1,681,193	0	1,681,193	0	1,681,193
130	DIRECT ASSIGNMENT	658		658	0	658	0	658
131	TOTAL ACCOUNT 352	47,082,813		47,082,813	9,282,506	56,365,319	0	56,365,319
132								
133	353 / STATION EQUIPMENT - SYSTEM SERVICE	299,830,555		299,830,555	33,992,621	333,823,176	1,952,735	335,775,911
134	TRANSMISSION RETAIL	20,066,422		20,066,422	0	20,066,422	0	20,066,422
135	DIRECT ASSIGNMENT	74,044		74,044	0	74,044	0	74,044
136	TOTAL ACCOUNT 353	319,971,021		319,971,021	33,992,621	353,963,642	1,952,735	355,916,377
137								
138	354 / TOWERS & FIXTURES - SYSTEM SERVICE	139,707,686		139,707,686	7,744,478	147,452,164	0	147,452,164
139	TRANSMISSION RETAIL	0		0	0	0	0	0
140	DIRECT ASSIGNMENT	0		0	0	0	0	0
141	TOTAL ACCOUNT 354	139,707,686		139,707,686	7,744,478	147,452,164	0	147,452,164
142								
143	355 / POLES & FIXTURES - SYSTEM SERVICE	97,598,663		97,598,663	4,743,610	102,342,273	0	102,342,273
144	TRANSMISSION RETAIL	35,858		35,858	0	35,858	0	35,858
145	DIRECT ASSIGNMENT	34,064		34,064	0	34,064	0	34,064
146	TOTAL ACCOUNT 355	97,668,585		97,668,585	4,743,610	102,412,195	0	102,412,195
147								
148	356 / OVERHEAD CONDUCTORS & DEVICES - SYSTEM SERVIC	165,709,012		165,709,012	5,140,214	170,849,227	2,016,879	172,866,106
149	TRANSMISSION RETAIL	159,892		159,892	0	159,892	0	159,892
150	DIRECT ASSIGNMENT	28,221		28,221	0	28,221	0	28,221
151	TOTAL ACCOUNT 356	165,897,125		165,897,125	5,140,214	171,037,340	2,016,879	173,054,219
152								
153	359 / ROADS & TRAILS - SYSTEM SERVICE	318,351		318,351	0	318,351	0	318,351
154	TRANSMISSION RETAIL	0		0	0	0	0	0
155	DIRECT ASSIGNMENT	0		0	0	0	0	0
156	TOTAL ACCOUNT 359	318,351		318,351	0	318,351	0	318,351
157								
158	TOTAL TRANSMISSION PLANT	803,602,485		803,602,485	62,200,462	865,802,947	3,969,614	869,772,561

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
159	***TABLE 1-ELECTRIC PLANT IN SERVICE***							
160								
161	DISTRIBUTION PLANT							
162	360 / LAND & LAND RIGHTS - SYSTEM SERVICE	4,729,098		4,729,098	16,092	4,745,190	0	4,745,190
163	PLUS: ADJUSTMENT FOR CIAC	89,946		89,946	0	89,946		89,946
164	NET DISTRIBUTION PLANT + CIAC	4,819,044		4,819,044	16,092	4,835,136	0	4,835,136
165								
166	361 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	28,653,521		28,653,521	2,127,095	30,780,615	0	30,780,615
167	PLUS: ADJUSTMENT FOR CIAC	6,129,068		6,129,068	0	6,129,068		6,129,068
168	NET DISTRIBUTION PLANT + CIAC	34,782,589		34,782,589	2,127,095	36,909,683	0	36,909,683
169								
170	362 / STATION EQUIPMENT - SYSTEM SERVICE	182,594,168		182,594,168	5,278,691	187,872,859	7,852,266	195,725,125
171	PLUS: ADJUSTMENT FOR CIAC	24,743,557		24,743,557	0	24,743,557		24,743,557
172	NET DISTRIBUTION PLANT + CIAC	207,337,725		207,337,725	5,278,691	212,616,416	0	212,616,416
173								
174	364 / POLES, TOWERS & FIXTURES	221,160,174		221,160,174	7,985,553	229,145,727	0	229,145,727
175	365 / OVERHEAD CONDUCTORS & DEVICES	118,697,240		118,697,240	3,775,300	122,472,539	771,499	123,244,038
176	366 / UNDERGROUND CONDUIT	48,258,864		48,258,864	1,081,949	49,340,813	0	49,340,813
177	367 / UNDERGROUND CONDUCTORS & DEVICES	188,310,616		188,310,616	7,171,939	195,482,555	0	195,482,555
178	368 / LINE TRANSFORMERS	408,105,839		408,105,839	12,881,257	420,987,096	0	420,987,096
179	369 / SERVICES	57,124,593		57,124,593	1,203,475	58,328,068	0	58,328,068
180	370 / ALL OTHER METERS	13,731,087		13,731,087	1,080,164	14,811,250	0	14,811,250
181	AMI	31,753,120		31,753,120	16,573,276	48,326,396	5,643,123	53,969,519
182	PRE-AMI (OREGON)	1,269,804		1,269,804	(1,269,804)	0	0	0
183	PRE-AMI (IDAHO)	41,108,636		41,108,636	0	41,108,636	0	41,108,636
184	TOTAL ACCOUNT 370	87,862,646		87,862,646	16,383,636	104,246,282		109,889,405
185	371 / INSTALLATIONS ON CUSTOMER PREMISES	2,701,332		2,701,332	75,667	2,776,999	0	2,776,999
186	373 / STREET LIGHTING SYSTEMS	4,301,388		4,301,388	75,244	4,376,633	0	4,376,633
187								
188	TOTAL DISTRIBUTION PLANT	1,352,499,478		1,352,499,478	58,055,898	1,410,555,376	14,266,888	1,424,822,264
189								
190	GENERAL PLANT							
191	389 / LAND & LAND RIGHTS	10,936,127		10,936,127	860,545	11,796,672	0	11,796,672
192	390 / STRUCTURES & IMPROVEMENTS	77,095,507		77,095,507	4,656,559	81,752,066	1,407,279	83,159,345
193	391 / OFFICE FURNITURE & EQUIPMENT	41,977,367		41,977,367	439,753	42,417,120	38,856	42,455,976
194	392 / TRANSPORTATION EQUIPMENT	59,206,167		59,206,167	1,209,292	60,415,459	0	60,415,459
195	393 / STORES EQUIPMENT	1,462,086		1,462,086	45,535	1,507,622	0	1,507,622
196	394 / TOOLS, SHOP & GARAGE EQUIPMENT	5,315,417		5,315,417	399,320	5,714,737	0	5,714,737
197	395 / LABORATORY EQUIPMENT	11,745,366		11,745,366	569,992	12,315,358	0	12,315,358
198	396 / POWER OPERATED EQUIPMENT	9,380,965		9,380,965	415,817	9,796,782	0	9,796,782
199	397 / COMMUNICATIONS EQUIPMENT	28,105,689		28,105,689	3,284,426	31,390,116	0	31,390,116
200	398 / MISCELLANEOUS EQUIPMENT	4,344,662		4,344,662	716,550	5,061,212	80,769	5,141,981
201								
202	TOTAL GENERAL PLANT	249,569,354		249,569,354	12,597,790	262,167,144	1,526,904	263,694,048
203								
204	TOTAL ELECTRIC PLANT IN SERVICE	4,231,369,395		4,231,369,395	165,872,190	4,397,241,585	31,599,458	4,428,841,043

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
205	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***							
206								
207	PRODUCTION PLANT							
208	310-316 / STEAM PRODUCTION	524,325,400		524,325,400	(4,386,362)	519,939,038	132,251	520,071,289
209	330-336 / HYDRAULIC PRODUCTION	331,327,415		331,327,415	14,042,625	345,370,039	36,437	345,406,476
210	340-346 / OTHER PRODUCTION	25,652,984		25,652,984	5,175,886	30,828,870	5,373	30,834,243
211	TOTAL PRODUCTION PLANT	881,305,799		881,305,799	14,832,149	896,137,948	174,060	896,312,008
212								
213	TRANSMISSION PLANT							
214	350 / LAND & LAND RIGHTS	5,205,369		5,205,369	448,463	5,653,832	0	5,653,832
215	352 / STRUCTURES & IMPROVEMENTS	20,240,079		20,240,079	744,746	20,984,825	4,431	20,989,256
216	353 / STATION EQUIPMENT	93,514,515		93,514,515	4,964,656	98,479,170	35,213	98,514,383
217	354 / TOWERS & FIXTURES	38,426,009		38,426,009	2,789,111	41,215,120	30,703	41,245,823
218	355 / POLES & FIXTURES	49,360,352		49,360,352	2,154,129	51,514,482	13,089	51,527,571
219	356 / OVERHEAD CONDUCTORS & DEVICES	51,017,819		51,017,819	2,549,007	53,566,827	20,947	53,587,773
220	359 / ROADS & TRAILS	255,124		255,124	3,126	258,250	0	258,250
221	TOTAL TRANSMISSION PLANT	258,019,268		258,019,268	13,653,238	271,672,506	104,383	271,776,889
222								
223	DISTRIBUTION PLANT							
224	360 / LAND & LAND RIGHTS	0		0	0	0	0	0
225	361 / STRUCTURES & IMPROVEMENTS	7,877,272		7,877,272	367,100	8,244,372	13,312	8,257,684
226	362 / STATION EQUIPMENT	43,937,278		43,937,278	917,451	44,854,729	55,989	44,910,718
227	364 / POLES, TOWERS & FIXTURES	106,774,907		106,774,907	5,631,495	112,406,402	65,672	112,472,074
228	365 / OVERHEAD CONDUCTORS & DEVICES	41,220,643		41,220,643	2,032,753	43,253,395	34,286	43,287,681
229	366 / UNDERGROUND CONDUIT	11,520,250		11,520,250	834,009	12,354,260	9,768	12,364,028
230	367 / UNDERGROUND CONDUCTORS & DEVICES	65,571,973		65,571,973	3,361,526	68,933,499	34,976	68,968,474
231	368 / LINE TRANSFORMERS	138,179,557		138,179,557	2,517,125	140,696,682	46,580	140,743,262
232	369 / SERVICES	35,836,492		35,836,492	1,406,461	37,242,953	13,142	37,256,094
233	370 / ALL OTHER METERS	4,597,152		4,597,152	905,929	5,503,081	(2,303)	5,500,778
234	AMI	2,035,440		2,035,440	2,263,546	4,298,987	225,559	4,524,545
235	PRE-AMI (OREGON)	1,151,479		1,151,479	(1,151,479)	0	0	0
236	PRE-AMI (IDAHO)	20,127,871		20,127,871	10,551,354	30,679,225	0	30,679,225
237	371 / INSTALLATIONS ON CUSTOMER PREMISES	2,318,482		2,318,482	(87,417)	2,231,065	144	2,231,210
238	373 / STREET LIGHTING SYSTEMS	3,199,915		3,199,915	112,032	3,311,947	182	3,312,129
239	TOTAL DISTRIBUTION PLANT	484,348,712		484,348,712	29,661,883	514,010,595	497,309	514,507,903
240								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
241	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***							
242								
243	GENERAL PLANT							
244	389 / LAND & LAND RIGHTS	0		0	0	0	0	0
245	390 / STRUCTURES & IMPROVEMENTS	21,297,426		21,297,426	1,120,519	22,417,945	28,331	22,446,276
246	391 / OFFICE FURNITURE & EQUIPMENT	24,068,255		24,068,255	2,104,295	26,172,550	216,768	26,389,318
247	392 / TRANSPORTATION EQUIPMENT	19,513,428		19,513,428	48,881	19,562,308	3,097	19,565,405
248	393 / STORES EQUIPMENT	503,958		503,958	35,680	539,638	1,980	541,617
249	394 / TOOLS, SHOP & GARAGE EQUIPMENT	2,381,690		2,381,690	187,712	2,569,402	3,645	2,573,048
250	395 / LABORATORY EQUIPMENT	5,654,997		5,654,997	192,167	5,847,164	9,825	5,856,989
251	396 / POWER OPERATED EQUIPMENT	3,403,467		3,403,467	541,070	3,944,537	10,005	3,954,543
252	397 / COMMUNICATIONS EQUIPMENT	15,066,746		15,066,746	1,322,853	16,389,599	65,449	16,455,048
253	398 / MISCELLANEOUS EQUIPMENT	1,825,132		1,825,132	333,608	2,158,740	10,831	2,169,571
254	TOTAL GENERAL PLANT	93,715,099		93,715,099	5,886,785	99,601,884	349,931	99,951,816
255								
256	AMORTIZATION OF DISALLOWED COSTS	7,149,284		7,149,284	(296,299)	6,852,985	0	6,852,985
257								
258	TOTAL ACCUM PROVISION DEPRECIATION	1,724,538,162		1,724,538,162	63,737,756	1,788,275,918	1,125,683	1,789,401,601
259								
260	AMORTIZATION OF OTHER UTILITY PLANT							
261	INTANGIBLE PLANT	5,057,847		5,057,847	854,524	5,912,370	94,728	6,007,098
262	HYDRAULIC PRODUCTION	13,333,257		13,333,257	1,965,517	15,298,774	0	15,298,774
263								
264	TOTAL AMORT OF OTHER UTILITY PLANT	18,391,104		18,391,104	2,820,040	21,211,144	94,728	21,305,872
265								
266	TOTAL ACCUM PROVISION FOR DEPR							
267	& AMORTIZATION OF OTHER UTILITY PLANT	1,742,929,265		1,742,929,265	66,557,797	1,809,487,062	1,220,411	1,810,707,473
268								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
269	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***							0
270								0
271	NET ELECTRIC PLANT IN SERVICE	2,488,440,130		2,488,440,130	99,314,393	2,587,754,523	30,379,047	2,618,133,570
272	LESS:							0
273	252 CUSTOMER ADVANCES FOR CONSTRUCTION							
274	POWER SUPPLY	0		0	0	0	0	0
275	OTHER	23,565,979		23,565,979	(6,304,446)	17,261,533	0	17,261,533
276	TOTAL CUSTOMER ADV FOR CONSTRUCTION	23,565,979		23,565,979	(6,304,446)	17,261,533	0	17,261,533
277								
278	ACCUMULATED DEFERRED INCOME TAXES							
279	190 / ACCUMULATED DEFERRED INCOME TAXES							
280	CUSTOMER ADVANCES FOR CONSTUCTION	(7,698,009)	0	(7,698,009)	1,578,962	(6,119,047)	0	(6,119,047)
281	OTHER	(15,819,891)	0	(15,819,891)	(155,054)	(15,974,945)	0	(15,974,945)
282	TOTAL ACCOUNT 190	(23,517,900)	0	(23,517,900)	1,423,908	(22,093,992)	0	(22,093,992)
283	281 / ACCELERATED AMORTIZATION	0		0	0	0	0	0
284	282 / OTHER PROPERTY	271,043,775	0	271,043,775	23,532,514	294,576,289	0	294,576,289
285	283 / OTHER	7,895,931	0	7,895,931	11,657,819	19,553,750	0	19,553,750
286	TOTAL ACCUM DEFERRED INCOME TAXES	255,421,806	0	255,421,806	36,614,241	292,036,047	0	292,036,047
287								
288	NET ELECTRIC PLANT IN SERVICE	2,209,452,345	0	2,209,452,345	69,004,598	2,278,456,943	30,379,047	2,308,835,990
289	ADD:							
290	WORKING CAPITAL							
291	151 / FUEL INVENTORY	27,299,230	(4,409,527)	22,889,703	2,641,799	25,531,502	0	25,531,502
292	154 & 163 / PLANT MATERIALS & SUPPLIES							
293	PRODUCTION - GENERAL	14,312,232		14,312,232	(200,499)	14,111,733	0	14,111,733
294	TRANSMISSION - GENERAL	13,300,192		13,300,192	(186,322)	13,113,870	0	13,113,870
295	DISTRIBUTION - GENERAL	14,267,912		14,267,912	(199,879)	14,068,033	0	14,068,033
296	OTHER - UNCLASSIFIED	5,029,573		5,029,573	(70,459)	4,959,114	0	4,959,114
297	TOTAL ACCOUNT 154 & 163	46,909,909		46,909,909	(657,159)	46,252,750	0	46,252,750
298	165 / PREPAID ITEMS							
299	AD VALOREM TAXES	1,745,549	(1,745,549)	0	0	0	0	0
300	OTHER PROD-RELATED PREPAYMENTS	87,305	(87,305)	0	0	0	0	0
301	INSURANCE	3,297,889	(3,297,889)	0	0	0	0	0
302	PENSION EXPENSE	552,552	(552,552)	0	0	0	0	0
303	PREPAID CONTRACTS	2,898,980	(2,898,980)	0	0	0	0	0
304	MISCELLANEOUS PREPAYMENTS	2,327,938	(2,327,938)	0	0	0	0	0
305	TOTAL ACCOUNT 165	10,910,213	(10,910,213)	0	0	0	0	0
306	WORKING CASH ALLOWANCE	27,728,850	(3,707,704)	24,021,147	3,195,707	27,216,854	173,796	27,390,650
307								
308	TOTAL WORKING CAPITAL	112,848,202	(19,027,444)	93,820,759	5,180,347	99,001,106	173,796	99,174,902
309								
310	NET ELECTRIC PLANT IN SERVICE	2,322,300,547	(19,027,444)	2,303,273,103	74,184,946	2,377,458,049	30,552,843	2,408,010,892

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
311	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***							
312								
313	NET ELECTRIC PLANT IN SERVICE	2,322,300,547	(19,027,444)	2,303,273,103	74,184,946	2,377,458,049	30,552,843	2,408,010,892
314	ADD:							
315	105 / PLANT HELD FOR FUTURE USE							
316	HYDRAULIC PRODUCTION	112,703	(112,703)	0	0	0	0	0
317	TRANS LAND & LAND RIGHTS	915,960	(915,960)	0	0	0	0	0
318	TRANS STRUCTURES & IMPROVEMENTS	382,388	(382,388)	0	0	0	0	0
319	TRANS STATION EQUIPMENT	32,400	(32,400)	0	0	0	0	0
320	DIST LAND & LAND RIGHTS	1,540,582	(1,540,582)	0	0	0	0	0
321	DIST STRUCTURES & IMPROVEMENTS	626,395	(626,395)	0	0	0	0	0
322	GEN LAND & LAND RIGHTS	3,392,933	(3,392,933)	0	0	0	0	0
323	GEN STRUCTURES & IMPROVEMENTS	72,785	(72,785)	0	0	0	0	0
324	TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0
325	TOTAL PLANT HELD FOR FUTURE USE	7,076,146	(7,076,146)	0	0	0	0	0
326								
327	114/115 - PRAIRIE ACQUISITION ADJUSMENT (ACCOUNT 406)	0	(35,977)	(35,977)	22,723	(13,254)	0	(13,254)
328								
329	DEFERRED PROGRAMS:							
330	182 / CONSERVATION PROGRAMS							
331	IDAHO DEFERRED CONSERVATION PROGRAMS	0		0	0	0	0	0
332	OREGON DEFERRED CONSERVATION PROGRAMS	0		0	0	0	0	0
333	TOTAL CONSERVATION PROGRAMS	0		0	0	0	0	0
334	182 / MISC. OTHER REGULATORY ASSETS							
335	OTHER DEFERRED	0		0	0	0	0	0
336	CUB FUND GRAND - (OPUC ORDER 10-406	30,100		30,100	(30,100)	0	0	0
337	ZGA ARCHITECTS & PLANNERS - IPUC ORDER 30722	0		0		0	0	0
338	PENSION DEFERRAL - OPUC ORDER 10-064	939,890		939,890	383,271	1,323,161	0	1,323,161
339	INTERVENOR FUNDING	46,052		46,052	(46,052)	0	0	0
340	GRID WEST - OPUC ORDER 06-483	59,128		59,128	(14,191)	44,937	0	44,937
341	GRID WEST - FERC	195,524		195,524	(83,796)	111,728	0	111,728
342	TOTAL OTHER REGULATORY ASSETS	1,270,694		1,270,694	209,132	1,479,826	0	1,479,826
343	186 / MISC. OTHER DEFERRED PROGRAMS				0			
344	AM. FALLS BOND REFINANCING	886,145		886,145	(62,552)	823,593	0	823,593
345	TOTAL DEFERRED PROGRAMS	2,156,839		2,156,839	146,580	2,303,419	0	2,303,419
346					0			
347	DEVELOPMENT OF IERCO RATE BASE				0			
348	INVESTMENT IN IERCO	67,582,237	(85,531)	67,496,706	7,609,643	75,106,349	0	75,106,349
349	PREPAID COAL ROYALTIES	1,464,357		1,464,357	(68,132)	1,396,225	0	1,396,225
350	NOTES PAYABLE TO/RECEIVABLE FROM SUBSIDIARY	19,880,651		19,880,651	(7,387,381)	12,493,270	0	12,493,270
351	TOTAL SUBSIDIARY RATE BASE	88,927,245	(85,531)	88,841,714	154,130	88,995,844	0	88,995,844
352					0			
353	TOTAL COMBINED RATE BASE	2,420,460,776	(26,225,097)	2,394,235,679	74,508,379	2,468,744,058	30,552,843	2,499,296,901

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
354	***TABLE 4-OPERATING REVENUES***							
355	FIRM ENERGY SALES & OATT REFUNDS							
356	440-448 / RETAIL	870,300,690	(51,202,226)	819,098,464	32,941,318	852,039,782	0	852,039,782
357	442 / HOKU BLOCK 1 ENERGY	27,572	0	27,572	23,953,827	23,981,399	0	23,981,399
358	447 / FIRM SALES FOR RESALE	2,884,710	(496,988)	2,387,722	(2,387,722)	0	0	0
359	447 / SYSTEM OPPORTUNITY SALES	75,248,792	(2,518,092)	72,730,700	10,146,056	82,876,756	0	82,876,756
360	447 / SYSTEM OPPORTUNITY SALES - LOSSES	0	0	0	0	0	0	0
361	TOTAL SALES OF ELECTRICITY	948,461,764	(54,217,306)	894,244,458	64,653,479	958,897,937	0	958,897,937
362								
363	OTHER OPERATING REVENUES							
364	415 / MERCHANDISING REVENUES	0	784,615	784,615	0	784,615	0	784,615
365								
366	449 / OATT TARIFF REFUND							
367	NETWORK	0	0	0		0	0	0
368	POINT-TO-POINT	0	0	0		0	0	0
369	TOTAL ACCOUNT 449	0	0	0		0	0	0
370								
371	451 / MISCELLANEOUS SERVICE REVENUES	3,532,832		3,532,832	0	3,532,832	0	3,532,832
372						0		
373	454 / RENTS FROM ELECTRIC PROPERTY					0		
374	SUBSTATION EQUIPMENT	9,968,654		9,968,654		9,968,654	0	9,968,654
375	TRANSFORMER RENTALS	17,330		17,330		17,330	0	17,330
376	LINE RENTALS	2,067,177		2,067,177		2,067,177	0	2,067,177
377	COGENERATION	659,903		659,903	197,439	857,342	0	857,342
378	REAL ESTATE RENTS	240,575		240,575		240,575	0	240,575
379	DARK FIBER PROJECT	448,000		448,000		448,000	0	448,000
380	POLE ATTACHMENTS	1,660,518		1,660,518		1,660,518	0	1,660,518
381	FACILITIES CHARGES	5,740,276	1,786,566	7,526,843	(1,214,027)	6,312,816	0	6,312,816
382	OTHER RENTALS	338,693		338,693		338,693	0	338,693
383	MISCELLANEOUS	0		0		0	0	0
384	TOTAL ACCOUNT 454	21,141,127	1,786,566	22,927,693	(1,016,588)	21,911,105	0	21,911,105
385								
386	456 / OTHER ELECTRIC REVENUES							
387	TRANSMISSION NETWORK SERVICES	4,054,908		4,054,908	739,280	4,794,188	0	4,794,188
388	TRANSMISSION NETWORK SERVICES - DIST FACILITIES	685,063		685,063	0	685,063	0	685,063
389	TRANSMISSION - POINT-TO-POINT & OTHER	10,658,431		10,658,431	1,799,219	12,457,650	0	12,457,650
390	PHOTOVOLTAIC STATION SERVICE	5,007		5,007	0	5,007	0	5,007
391	ENERGY EFFICIENCY RIDER	44,184,056	(44,184,056)	0	0	0	0	0
392	STANDBY SERVICE CHARGE	309,185		309,185	0	309,185	0	309,185
393	SIERRA PACIFIC USAGE CHARGE	(55,846)		(55,846)	55,846	(0)	0	(0)
394	ANTELOPE	73,824		73,824	0	73,824	0	73,824
395	MISCELLANEOUS	1,769		1,769	0	1,769	0	1,769
396	TOTAL ACCOUNT 456	59,916,397	(44,184,056)	15,732,341	2,594,345	18,326,686	0	18,326,686
397								
398	TOTAL OTHER OPERATING REVENUES	84,590,356	(41,612,875)	42,977,481	1,577,757	44,555,238	0	44,555,238
399								
400	TOTAL OPERATING REVENUES	1,033,052,120	(95,830,181)	937,221,939	66,231,236	1,003,453,175	0	1,003,453,175

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
401	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
402	STEAM POWER GENERATION							
403	OPERATION							
404	500 / SUPERVISION & ENGINEERING	1,888,571	0	1,888,571	290,346	2,178,917	9,936	2,188,853
405	501 / FUEL	146,926,801	32,099	146,958,900	2,395,801	149,354,701	0	149,354,701
406	502 / STEAM EXPENSES							
407	LABOR	2,630,419		2,630,419		2,630,419	0	2,630,419
408	OTHER	4,707,142		4,707,142	1,280,002	5,987,144	0	5,987,144
409	TOTAL ACCOUNT 502	7,337,561		7,337,561	1,280,002	8,617,563	0	8,617,563
410	505 / ELECTRIC EXPENSES							
411	LABOR	1,173,413		1,173,413		1,173,413	0	1,173,413
412	OTHER	966,780		966,780	373,346	1,340,126	0	1,340,126
413	TOTAL ACCOUNT 505	2,140,193		2,140,193	373,346	2,513,539	0	2,513,539
414	506 / MISCELLANEOUS EXPENSES	9,797,756	(64,325)	9,733,431	1,705,192	11,438,623	1,021	11,439,644
415	507 / RENTS	229,316		229,316	40,002	269,318	0	269,318
416	STEAM OPERATION EXPENSES	168,320,198	(32,226)	168,287,972	6,084,689	174,372,661	10,957	174,383,618
417								
418	MAINTENANCE							
419	510 / SUPERVISION & ENGINEERING	2,292,767		2,292,767	399,962	2,692,729	0	2,692,729
420	511 / STRUCTURES	309,374		309,374	53,969	363,343	0	363,343
421	512 / BOILER PLANT							
422	LABOR	6,236,518		6,236,518		6,236,518	0	6,236,518
423	OTHER	9,831,314		9,831,314	2,802,957	12,634,271	0	12,634,271
424	TOTAL ACCOUNT 512	16,067,832		16,067,832	2,802,957	18,870,789	0	18,870,789
425	513 / ELECTRIC PLANT							
426	LABOR	1,993,219		1,993,219		1,993,219	0	1,993,219
427	OTHER	1,922,071		1,922,071	683,005	2,605,076	0	2,605,076
428	TOTAL ACCOUNT 513	3,915,290		3,915,290	683,005	4,598,295	0	4,598,295
429	514 / MISCELLANEOUS STEAM PLANT	3,753,015		3,753,015	654,696	4,407,711	0	4,407,711
430	STEAM MAINTENANCE EXPENSES	26,338,278	0	26,338,278	4,594,589	30,932,867	0	30,932,867
431	TOTAL STEAM GENERATION EXPENSES	194,658,476	(32,226)	194,626,250	10,679,278	205,305,528	10,957	205,316,485
432								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
433	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
434	HYDRAULIC POWER GENERATION							
435	OPERATION							
436	535 / SUPERVISION & ENGINEERING	5,362,099	(66)	5,362,033	190,700	5,552,733	163,743	5,716,476
437	536 / WATER FOR POWER	7,322,751	(22)	7,322,729	243,349	7,566,078	22,062	7,588,140
438	537 / HYDRAULIC EXPENSES	10,671,807	(2,500)	10,669,307	1,099,261	11,768,568	184,740	11,953,308
439	538 / ELECTRIC EXPENSES							
440	LABOR	1,133,916		1,133,916		1,133,916	44,866	1,178,782
441	OTHER	431,926		431,926	55,419	487,345	0	487,345
442	TOTAL ACCOUNT 538	1,565,842		1,565,842	55,419	1,621,261	44,866	1,666,127
443	539 / MISCELLANEOUS EXPENSES	2,895,723	(351)	2,895,372	101,775	2,997,147	74,311	3,071,458
444	540 / RENTS	406,432		406,432	13,404	419,836	0	419,836
445	HYDRAULIC OPERATION EXPENSES	28,224,654	(2,939)	28,221,715	1,703,908	29,925,623	489,722	30,415,345
446								
447	MAINTENANCE							
448	541 / SUPERVISION & ENGINEERING	1,967,876		1,967,876	70,356	2,038,232	64,589	2,102,821
449	542 / STRUCTURES	1,155,653		1,155,653	40,462	1,196,115	28,310	1,224,425
450	543 / RESERVOIRS, DAMS & WATERWAYS	1,368,191		1,368,191	47,243	1,415,434	25,016	1,440,450
451	544 / ELECTRIC PLANT							
452	LABOR	1,989,149		1,989,149		1,989,149	78,705	2,067,854
453	OTHER	1,188,662		1,188,662	111,429	1,300,091	0	1,300,091
454	TOTAL ACCOUNT 544	3,177,811		3,177,811	111,429	3,289,240	78,705	3,367,945
455	545 / MISCELLANEOUS HYDRAULIC PLANT	3,029,473		3,029,473	106,310	3,135,783	76,527	3,212,310
456	HYDRAULIC MAINTENANCE EXPENSES	10,699,004	0	10,699,004	375,800	11,074,804	273,146	11,347,950
457	TOTAL HYDRAULIC GENERATION EXPENSES	38,923,658	(2,939)	38,920,719	2,079,708	41,000,427	762,868	41,763,295

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
458	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							0
459	OTHER POWER GENERATION							
460	OPERATION							
461	546 / SUPERVISION & ENGINEERING	328,417		328,417	11,785	340,202	11,348	351,550
462	547 / FUEL							
463	DIESEL FUEL	14,672		14,672		14,672	0	14,672
464	OTHER	12,731,280	(7,549,380)	5,181,900	(223,335)	4,958,565	0	4,958,565
465	TOTAL ACCOUNT 547	12,745,952	(7,549,380)	5,196,572	(223,335)	4,973,237	0	4,973,237
466	548 / GENERATING EXPENSES							
467	LABOR	0		0		0	12,967	12,967
468	OTHER	448,744		448,744	15,888	464,632	0	464,632
469	TOTAL ACCOUNT 548	448,744		448,744	15,888	464,632	12,967	477,599
470	549 / MISCELLANEOUS EXPENSES	450,180		450,180	15,911	466,091	12,784	478,875
471	550 / RENTS	0		0		0	0	0
472	OTHER POWER OPER EXPENSES	13,973,293	(7,549,380)	6,423,913	(179,751)	6,244,162	37,099	6,281,261
473								
474	MAINTENANCE							
475	551 / SUPERVISION & ENGINEERING	43		43	1	44	0	44
476	552 / STRUCTURES	182,043		182,043	6,433	188,476	5,060	193,536
477	553 / GENERATING & ELECTRIC PLANT			0		0		
478	LABOR	0		0		0	3,509	3,509
479	OTHER	118,533	0	118,533	4,209	122,742	0	122,742
480	TOTAL ACCOUNT 553	118,533	0	118,533	4,209	122,742	3,509	126,251
481	554 / MISCELLANEOUS EXPENSES	1,077,264		1,077,264	1,294,436	2,371,700	14,054	2,385,754
482	OTHER POWER MAINT EXPENSES	1,377,883	0	1,377,883	1,305,079	2,682,962	22,623	2,705,585
483	TOTAL OTHER POWER GENERATION EXP	15,351,176	(7,549,380)	7,801,796	1,125,328	8,927,124	59,722	8,986,846
484								
485	OTHER POWER SUPPLY EXPENSE							
486	555.0 / PURCHASED POWER							
487	POWER EXPENSE	81,871,679	(28,651,579)	53,220,100	17,740,613	70,960,713	0	70,960,713
488	TRANSMISSION LOSSES	1,006,538	0	1,006,538	359,462	1,366,000	0	1,366,000
489	TOTAL 555.0/PURCHASED POWER	82,878,217	(28,651,579)	54,226,638	18,100,075	72,326,713	0	72,326,713
490	555.1 / COGENERATION & SMALL POWER PROD			0		0		
491	CAPACITY RELATED	2,815,124	(2,815,124)	0	0	0	0	0
492	ENERGY RELATED	52,156,994	58,197,321	110,354,316	18,696,906	129,051,222	0	129,051,222
493	TOTAL 555.1/CSPP	54,972,118	55,382,198	110,354,316	18,696,906	129,051,222	0	129,051,222
494	555/TOTAL	137,850,335	26,730,619	164,580,954	36,796,981	201,377,935	0	201,377,935
495	556 / LOAD CONTROL & DISPATCHING EXPENSES	160		160	5	165	0	165
496	557 / OTHER EXPENSES							
497	PCA/ EPC ACCOUNTS	51,225,683	(51,225,683)	0		0	0	0
498	OTHER	2,569,334		2,569,334	91,215	2,660,549	77,912	2,738,461
499	557/TOTAL	53,795,017	(51,225,683)	2,569,334	91,215	2,660,549	77,912	2,738,461
500	TOTAL OTHER POWER SUPPLY EXPENSES	191,645,512	(24,495,064)	167,150,448	36,888,201	204,038,649	77,912	204,116,561
1	TOTAL PRODUCTION EXPENSES	440,578,822	(32,079,609)	408,499,213	50,772,515	459,271,728	911,459	460,183,187

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
2	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***			0		0		
3	TRANSMISSION EXPENSES			0		0		
4	OPERATION			0		0		
5	560 / SUPERVISION & ENGINEERING	2,992,955	(130)	2,992,825	104,884	3,097,709	74,228	3,171,937
6	561 / LOAD DISPATCHING	2,953,094	(76)	2,953,018	105,999	3,059,017	103,127	3,162,144
7	562 / STATION EXPENSES	1,987,214		1,987,214	70,228	2,057,442	55,632	2,113,074
8	563 / OVERHEAD LINE EXPENSES	660,035		660,035	2,386,852	3,046,887	12,886	3,059,773
9	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	5,918,507		5,918,507	2,060,093	7,978,600	0	7,978,600
10	566 / MISCELLANEOUS EXPENSES	336,835		336,835	11,205	348,040	1,179	349,219
11	567 / RENTS	1,569,168		1,569,168	612,921	2,182,089	0	2,182,089
12	TOTAL TRANSMISSION OPERATION	16,417,808	(206)	16,417,602	5,352,183	21,769,785	247,052	22,016,837
13								
14	MAINTENANCE							
15	568 / SUPERVISION & ENGINEERING	540,340		540,340	18,248	558,588	5,065	563,653
16	569 / STRUCTURES	419,219		419,219	14,897	434,116	12,604	446,720
17	570 / STATION EQUIPMENT	3,447,662	(9)	3,447,653	120,091	3,567,744	76,698	3,644,442
18	571 / OVERHEAD LINES	2,781,256	(11)	2,781,245	94,398	2,875,643	33,042	2,908,685
19	573 / MISCELLANEOUS PLANT	(40)		(40)	(2)	(42)	0	(42)
20	TOTAL TRANSMISSION MAINTENANCE	7,188,437	(20)	7,188,417	247,632	7,436,049	127,409	7,563,458
21								
22	TOTAL TRANSMISSION EXPENSES	23,606,245	(226)	23,606,019	5,599,815	29,205,834	374,461	29,580,295

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
23	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
24	DISTRIBUTION EXPENSES							
25	OPERATION							
26	580 / SUPERVISION & ENGINEERING	3,713,391	(1,162)	3,712,229	132,086	3,844,315	111,849	3,956,164
27	581 / LOAD DISPATCHING	3,419,960		3,419,960	122,808	3,542,768	116,327	3,659,095
28	582 / STATION EXPENSES	1,277,818	(100)	1,277,718	44,913	1,322,631	33,282	1,355,913
29	583 / OVERHEAD LINE EXPENSES	3,029,340	(74)	3,029,266	107,642	3,136,908	97,101	3,234,009
30	584 / UNDERGROUND LINE EXPENSES	1,792,342	(71)	1,792,271	61,166	1,853,437	25,348	1,878,785
31	585 / STREET LIGHTING & SIGNAL SYSTEMS	79,537		79,537	2,780	82,317	2,496	84,813
32	586 / METER EXPENSES	4,219,271	(35)	4,219,236	25,493	4,244,729	0	4,244,729
33	587 / CUSTOMER INSTALLATIONS EXPENSE	1,521,427	(55)	1,521,372	53,651	1,575,023	41,458	1,616,481
34	588 / MISCELLANEOUS EXPENSES	5,004,179	(605)	5,003,574	175,396	5,178,970	122,370	5,301,340
35	589 / RENTS	440,787		440,787	150,324	591,111	4	591,115
36	TOTAL DISTRIBUTION OPERATION	24,498,052	(2,102)	24,495,950	876,259	25,372,209	550,235	25,922,444
37								
38	MAINTENANCE							
39	590 / SUPERVISION & ENGINEERING	371,979		371,979	13,294	385,273	12,016	397,289
40	591 / STRUCTURES	(11,385)		(11,385)	(376)	(11,761)	0	(11,761)
41	592 / STATION EQUIPMENT	3,774,723	(113)	3,774,610	131,767	3,906,377	86,662	3,993,039
42	593 / OVERHEAD LINES	14,297,636	(7,433)	14,290,203	489,037	14,779,240	202,962	14,982,202
43	594 / UNDERGROUND LINES	1,003,404		1,003,404	35,257	1,038,661	25,533	1,064,194
44	595 / LINE TRANSFORMERS	448,157		448,157	14,863	463,020	982	464,002
45	596 / STREET LIGHTING & SIGNAL SYSTEMS	587,953		587,953	20,401	608,354	12,945	621,299
46	597 / METERS	700,080		700,080	3,933	704,013	0	704,013
47	598 / MISCELLANEOUS PLANT	137,583		137,583	4,833	142,416	4,239	146,655
48	TOTAL DISTRIBUTION MAINTENANCE	21,310,130	(7,546)	21,302,584	713,009	22,015,593	345,339	22,360,932
49	TOTAL DISTRIBUTION EXPENSES	45,808,182	(9,648)	45,798,534	1,589,268	47,387,802	895,574	48,283,376
50								
51	CUSTOMER ACCOUNTING EXPENSES							
52	901 / SUPERVISION	410,702	(103)	410,599	14,722	425,321	14,229	439,550
53	902 / METER READING	4,026,937		4,026,937	(1,833,435)	2,193,502	0	2,193,502
54	903 / CUSTOMER RECORDS & COLLECTIONS	12,988,730	(69)	12,988,661	450,982	13,439,643	273,279	13,712,922
55	904 / UNCOLLECTIBLE ACCOUNTS	4,638,855		4,638,855	0	4,638,855	0	4,638,855
56	905 / MISC EXPENSES	342		342	12	354	0	354
57	TOTAL CUSTOMER ACCOUNTING EXPENSES	22,065,566	(172)	22,065,394	(1,367,719)	20,697,675	287,508	20,985,183
58								
59	CUSTOMER SERVICES & INFORMATION EXPENSES							
60	907 / SUPERVISION	352,778	(244)	352,534	12,606	365,140	11,052	376,192
61	908 / CUSTOMER ASSISTANCE							
62	SYSTEM CONSERVATION	333,928		333,928		333,928	0	333,928
63	OTHER	51,625,921	(44,187,183)	7,438,738	(1,352,887)	6,085,851	143,730	6,229,581
64	TOTAL ACCOUNT 908	51,959,849	(44,187,183)	7,772,666	(1,352,887)	6,419,779	143,730	6,563,509
65	909 / INFORMATION & INSTRUCTIONAL	31,517		31,517	1,040	32,557	0	32,557
66	910 / MISCELLANEOUS EXPENSES	864,003	(329)	863,674	30,207	893,881	20,117	913,998
67	TOTAL CUST SERV & INFORMATN EXPENSES	53,208,147	(44,187,756)	9,020,391	(1,309,034)	7,711,357	174,898	7,886,255

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
68	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
69	ADMINISTRATIVE & GENERAL EXPENSES							
70	920 / ADMINISTRATIVE & GENERAL SALARIES	63,660,597	(16,398,928)	47,261,669	8,384,695	55,646,364	1,618,018	57,264,382
71	921 / OFFICE SUPPLIES	13,613,991	(17,258)	13,596,733	1,300,867	14,897,600	7,681	14,905,281
72	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	(27,799,634)		(27,799,634)	(998,665)	(28,798,299)	0	(28,798,299)
73	923 / OUTSIDE SERVICES	7,210,630	(7,395)	7,203,235	237,808	7,441,043	0	7,441,043
74	924 / PROPERTY INSURANCE					0		0
75	PRODUCTION - STEAM	809,837		809,837		809,837	0	809,837
76	ALL RISK & MISCELLANEOUS	2,519,740		2,519,740	5,031	2,524,771	21,166	2,545,937
77	TOTAL ACCOUNT 924	3,329,577		3,329,577	5,031	3,334,608	21,166	3,355,774
78	925 / INJURIES & DAMAGES	5,668,380		5,668,380	187,461	5,855,841	6,440	5,862,281
79	926 / EMPLOYEE PENSIONS & BENEFITS	25,926,077	(1,027)	25,925,050	618,379	26,543,429	0	26,543,429
80	EMPLOYEE PENSIONS & BENEFITS - OREGON	884,236		884,236	8,788	893,024	0	893,024
81	EMPLOYEE PENSIONS & BENEFITS - IDAHO	3,159,800		3,159,800	13,993,913	17,153,713	0	17,153,713
82	EMPLOYEE PENSIONS & BENEFITS - FERC	60,986		60,986	129,964	190,950	0	190,950
83	927 / FRANCHISE REQUIREMENTS	2,549		2,549	84	2,633	0	2,633
84	928 / REGULATORY COMMISSION EXPENSES							
85	928.101 / FERC ADMIN ASSESS & SECURITIES							
86	CAPACITY RELATED	1,661,164		1,661,164	131,221	1,792,385	0	1,792,385
87	ENERGY RELATED	706,272		706,272	55,791	762,063	0	762,063
88	928.101 / FERC ORDER 472	466,188		466,188	36,825	503,013	0	503,013
89	928.101 / FERC MISCELLANEOUS	539,362		539,362	42,607	581,969	0	581,969
90	928.102 FERC RATE CASE	704		704	23	727	0	727
91	928.104 / FERC OREGON HYDRO	158,506		158,506	5,227	163,733	0	163,733
92	928.202 / IDAHO PUC -RATE CASE	1,024		1,024	54,349	55,373	0	55,373
93	928.203 / IDAHO PUC - OTHER	31,419	(5,748)	25,671	42,077	67,748	0	67,748
94	928.301 / OREGON PUC - FILING FEES	0		0		0	0	0
95	928.302 / OREGON PUC - RATE CASE	6,532		6,532	216	6,748	0	6,748
96	928.303 / OREGON PUC - OTHER	226,666		226,666	72,596	299,262	0	299,262
97	IPC/PUC JSS TRUE-UP ADJ	0		0		0	0	0
98	TOTAL ACCOUNT 928	3,797,837	(5,748)	3,792,089	440,932	4,233,021	0	4,233,021
99	929 / DUPLICATE CHARGES	0		0		0	0	0
100	930.1 / GENERAL ADVERTISING	417,950	(417,950)	0		0	0	0
101	930.2 / MISCELLANEOUS EXPENSES	3,826,102	(181,010)	3,645,092	140,403	3,785,495	5,253	3,790,748
102	931 / RENTS	12,600		12,600	12,588	25,188	0	25,188
103	TOTAL ADM & GEN OPERATION	103,771,678	(17,029,316)	86,742,362	24,462,249	111,204,611	1,658,560	112,863,171
104	PLUS:			0		0		0
105	935 / GENERAL PLANT MAINTENANCE	4,182,611	(16)	4,182,595	145,593	4,328,188	42,431	4,370,619
106	416 / MERCHANDISING EXPENSE	0	614,155	614,155	0	614,155	0	614,155
107	TOTAL OPER & MAINT EXPENSES	693,221,251	(92,692,588)	600,528,663	79,892,687	680,421,350	4,344,891	684,766,241

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
108	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***							
109								
110	DEPRECIATION EXPENSE							
111	310-316 / STEAM PRODUCTION	18,372,191		18,372,191	454,375	18,826,566	264,502	19,091,068
112	330-336 / HYDRAULIC PRODUCTION	15,364,474		15,364,474	(8,871)	15,355,603	72,873	15,428,476
113	340-346 / OTHER PRODUCTION	4,940,258		4,940,258	493,319	5,433,577	10,746	5,444,322
114	TOTAL PRODUCTION PLANT	38,676,923		38,676,923	938,824	39,615,746	348,121	39,963,867
115								
116	TRANSMISSION PLANT							
117	350 / LAND & LAND RIGHTS	433,529		433,529	21,518	455,047	0	455,047
118	352 / STRUCTURES & IMPROVEMENTS	772,335		772,335	173,785	946,121	8,863	954,983
119	353 / STATION EQUIPMENT	6,540,842		6,540,842	758,516	7,299,358	70,426	7,369,784
120	354 / TOWERS & FIXTURES	2,730,078		2,730,078	148,805	2,878,883	61,405	2,940,288
121	355 / POLES & FIXTURES	2,735,230		2,735,230	138,259	2,873,489	26,178	2,899,667
122	356 / OVERHEAD CONDUCTORS & DEVICES	3,179,995		3,179,995	100,323	3,280,318	41,894	3,322,211
123	359 / ROADS & TRAILS	3,120		3,120	13	3,133	0	3,133
124	TOTAL TRANSMISSION PLANT	16,395,129		16,395,129	1,341,219	17,736,349	208,766	17,945,115
125								
126	DISTRIBUTION PLANT							
127	360 / LAND & LAND RIGHTS	0		0	0	0	0	0
128	361 / STRUCTURES & IMPROVEMENTS	529,734		529,734	36,869	566,603	26,625	593,228
129	362 / STATION EQUIPMENT	3,451,030		3,451,030	101,697	3,552,727	111,979	3,664,706
130	364 / POLES, TOWERS & FIXTURES	7,265,471		7,265,471	256,249	7,521,720	131,345	7,653,065
131	365 / OVERHEAD CONDUCTORS & DEVICES	3,498,030		3,498,030	110,840	3,608,870	68,572	3,677,442
132	366 / UNDERGROUND CONDUIT	941,119		941,119	21,927	963,045	19,536	982,581
133	367 / UNDERGROUND CONDUCTORS & DEVICES	3,704,492		3,704,492	134,803	3,839,295	69,952	3,909,247
134	368 / LINE TRANSFORMERS	6,806,033		6,806,033	206,891	7,012,925	93,160	7,106,085
135	369 / SERVICES	1,764,643		1,764,643	38,549	1,803,192	26,283	1,829,475
136	370 / ALL OTHER METERS	991,179		991,179	38,361	1,029,540	(4,606)	1,024,935
137	AMI	2,101,632		2,101,632	1,125,095	3,226,727	451,117	3,677,845
138	PRE-AMI (OREGON)	439,567		439,567	(439,567)	0	0	0
139	PRE-AMI (IDAHO)	10,551,354		10,551,354	0	10,551,354	0	10,551,354
140	371 / INSTALLATIONS ON CUSTOMER PREMISES	18,535		18,535	10,433	28,967	289	29,256
141	373 / STREET LIGHTING SYSTEMS	175,691		175,691	3,377	179,068	365	179,433
142	TOTAL DISTRIBUTION PLANT	42,238,509		42,238,509	1,645,524	43,884,033	994,617	44,878,651

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
143	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***							
144								
145	GENERAL PLANT							
146	389 / LAND & LAND RIGHTS	0				0	0	0
147	390 / STRUCTURES & IMPROVEMENTS	1,798,012		1,798,012	100,272	1,898,283	56,663	1,954,946
148	391 / OFFICE FURNITURE & EQUIPMENT	6,975,480		6,975,480	442,462	7,417,942	433,535	7,851,477
149	392 / TRANSPORTATION EQUIPMENT	227,309		227,309	(4,894)	222,415	0	222,415
150	393 / STORES EQUIPMENT	65,623		65,623	15,722	81,345	3,959	85,304
151	394 / TOOLS, SHOP & GARAGE EQUIPMENT	227,325		227,325	48,850	276,175	7,291	283,465
152	395 / LABORATORY EQUIPMENT	570,437		570,437	94,421	664,858	19,649	684,508
153	396 / POWER OPERATED EQUIPMENT	104,001		104,001	(104,001)	0	0	0
154	397 / COMMUNICATIONS EQUIPMENT	1,704,298		1,704,298	200,223	1,904,521	130,898	2,035,419
155	398 / MISCELLANEOUS EQUIPMENT	412,451		412,451	70,920	483,371	21,663	505,034
156	TOTAL GENERAL PLANT	12,084,935		12,084,935	863,976	12,948,911	673,658	13,622,568
157								
158	TOTAL DEPRECIATION EXPENSE	109,395,496		109,395,496	4,789,543	114,185,039	2,225,161	116,410,200
159								
160	DEPRECIATION ON DISALLOWED COSTS	(296,299)		(296,299)	0	(296,299)	0	(296,299)
161	TOTAL DEPRECIATION EXPENSE	109,099,197		109,099,197	4,789,543	113,888,740	2,225,161	116,113,901
162								
163	AMORTIZATION EXPENSE							
164	INTANGIBLE PLANT	6,857,301		6,857,301	184,774	7,042,075	189,455	7,231,531
165	HYDRAULIC PRODUCTION	0		0		0	0	0
166	ADJUSTMENTS, GAINS & LOSSES	(501,542)	478,819	(22,723)	0	(22,723)	0	(22,723)
167	TOTAL AMORTIZATION EXPENSE	6,355,759	478,819	6,834,578	184,774	7,019,352	189,455	7,208,808
168								
169	TOTAL DEPRECIATION & AM0RTIZATION EXP	115,454,956	478,819	115,933,775	4,974,317	120,908,092	2,414,617	123,322,709

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
170	***TABLE 7-TAXES OTHER THAN INCOME TAXES***							
171								
172	TAXES OTHER THAN INCOME							
173	FEDERAL TAXES							
174	SOCIAL SECURITY	12,457,819	(12,457,819)	0		0		0
175	UNEMPLOYMENT	120,285	(120,285)	0		0		0
176	LESS PAYROLL DEDUCTION	(13,686,350)	13,686,350	0		0		0
177								
178	STATE TAXES							
179	AD VALOREM TAXES							
180	JIM BRIDGER STATION	1,194,866		1,194,866	217,681	1,412,547		1,412,547
181	VALMY	1,084,300		1,084,300	197,538	1,281,838		1,281,838
182	BOARDMAN	260,775		260,775	47,508	308,283		308,283
183	OTHER-PRODUCTION PLANT	4,467,955		4,467,955	133,285	4,601,240	32,428	4,633,668
184	OTHER-TRANSMISSION PLANT	3,842,054		3,842,054	1,543,998	5,386,052	17,864	5,403,916
185	OTHER-DISTRIBUTION PLANT	7,640,112		7,640,112	813,702	8,453,814	74,188	8,528,002
186	OTHER-GENERAL PLANT	1,263,031		1,263,031	93,556	1,356,587	7,939	1,364,526
187	SUB-TOTAL	19,753,093		19,753,093	3,047,271	22,800,364	132,419	22,932,783
188								
189	LICENSES - HYDRO PROJECTS	4,250		4,250	580	4,830		4,830
190								
191	REGULATORY COMMISSION FEES							
192	STATE OF IDAHO	1,837,184		1,837,184	0	1,837,184		1,837,184
193	STATE OF OREGON	92,603		92,603	48,339	140,942		140,942
194	STATE OF NEVADA	0		0	0			0
195								
196	FRANCHISE TAXES							
197	STATE OF OREGON	713,129		713,129	(32,970)	680,159		680,159
198	STATE OF NEVADA	0		0	0	0		0
199								
200	OTHER STATE TAXES							
201	UNEMPLOYMENT TAXES	1,108,246	(1,108,246)	0	0	0		0
202	HYDRO GENERATION KWH TAX	1,415,000		1,415,000	317,697	1,732,697		1,732,697
203	IRRIGATION-PIC	230,778		230,778	73,153	303,932		303,932
204								
205	TOTAL TAXES OTHER THAN INCOME	24,046,036	0	24,046,036	3,454,070	27,500,107	132,419	27,632,526

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
206	***TABLE 8-REGULATORY DEBITS & CREDITS***							
207	REGULATORY DEBITS/CREDITS							
208	STATE OF IDAHO	0		0	0	0		0
209	STATE OF OREGON	21,955		21,955	5,802	27,757		27,757
210								
211	TOTAL REGULATORY DEBITS/CREDITS	21,955	0	21,955	5,802	27,757		27,757
212								
213								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
214	***TABLE 9-INCOME TAXES***							
215								
216	410/411 NET PROVISION FOR DEFERRED INCOME TAXES							
217	ACCOUNT #282 - RELATED	2,760,109	0	2,760,109	42,563,457	45,323,566	0	45,323,566
218	ACCOUNT #190 & #283 - RELATED	(363,981)	0	(363,981)	(5,383,128)	(5,747,109)	0	(5,747,109)
219	TOTAL NET PROVISION FOR DEFERRED INCOME TAXES	2,396,127	0	2,396,127	37,180,330	39,576,457	0	39,576,457
220								
221	411.4 - INVESTMENT TAX CREDIT ADJUSTMENT	(1,533,190)	0	(1,533,190)	(1,062,201)	(470,989)	0	(470,989)
222								
223	SUMMARY OF INCOME TAXES							
224								
225	TOTAL FEDERAL INCOME TAX	5,967,392	(12,896,763)	(6,929,371)	723,279	(4,663,905)	(2,260,207)	(6,924,112)
226								
227	STATE INCOME TAX							
228	STATE OF IDAHO	2,763,053	(1,819,716)	943,336	1,809,399	2,752,735	(406,624)	2,346,112
229	STATE OF OREGON	292,924	(92,528)	200,396	(248,487)	(48,092)	(20,676)	(68,768)
230	OTHER STATES	1,250	(22,348)	(21,098)	20,677	(421)	(6,892)	(7,313)
231	TOTAL STATE INCOME TAXES	3,057,226	(1,934,592)	1,122,634	1,581,589	2,704,222	(434,191)	2,270,031

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
232	***TABLE 10-CALCULATION OF FEDERAL INCOME TAX***							
233	OPERATING REVENUES	1,033,052,120	(95,830,181)	937,221,939	66,231,236	1,003,453,175	0	1,003,453,175
234						0		
235	OPERATING EXPENSES					0		0
236	OPERATION & MAINTENANCE	693,221,251	(92,692,588)	600,528,663	79,892,687	680,421,350	4,344,891	684,766,241
237	DEPRECIATION EXPENSE	109,099,197	0	109,099,197	4,789,543	113,888,740	2,225,161	116,113,901
238	AMORTIZATION OF LIMITED TERM PLANT	6,355,759	478,819	6,834,578	184,774	7,019,352	189,455	7,208,808
239	TAXES OTHER THAN INCOME	24,046,036	0	24,046,036	3,454,070	27,500,107	132,419	27,632,526
240	REGULATORY DEBITS/CREDITS	21,955	0	21,955	5,802	27,757	0	27,757
241	TOTAL OPERATING EXPENSES	832,744,199	(92,213,769)	740,530,429	88,326,876	828,857,305	6,891,926	835,749,232
242								
243	BOOK-TAX ADJUSTMENT	0	0	0	0	0	0	0
244								
245	INCOME BEFORE TAX ADJUSTMENTS	200,307,921	(3,616,412)	196,691,509	(22,095,640)	174,595,870	(6,891,926)	167,703,943
246								
247	INCOME STATEMENT ADJUSTMENTS							
248	INTEREST EXPENSE / SYNCHRONIZATION	84,600,361	0	84,600,361	(85,445)	84,514,916	0	84,514,916
249								
250	NET OPERATING INCOME BEFORE TAXES	115,707,560	(3,616,412)	112,091,148	(22,010,195)	90,080,954	(6,891,926)	83,189,027
251								
252	ALLOWANCE FOR AFUDC	27,226,240	(27,226,240)	0	0	0	0	0
253	FEDERAL INCOME TAX ADJUSTMENTS - PLANT	(104,566,571)	0	(104,566,571)	(11,731,411)	(116,297,982)	0	(116,297,982)
254	FEDERAL INCOME TAX ADJUSTMENTS - OTHER	(34,722,436)	0	(34,722,436)	45,911,996	15,595,809	0	15,595,809
255								
256	NET OPER INCOME BEFORE STATE INCOME TAXES	3,644,793	(30,842,652)	(27,197,859)	12,170,390	(10,621,219)	(6,891,926)	(17,513,146)
257								
258	TOTAL STATE INCOME TAXES (ALLOWED)	5,563,678	6,005,244	11,568,922	(8,864,699)	2,704,222	(434,191)	2,270,031
259								
260	TOTAL FEDERAL TAXABLE INCOME	(1,918,885)	(36,847,896)	(38,766,780)	21,035,090	(13,325,442)	(6,457,735)	(19,783,177)
261								
262	FEDERAL TAX AT 35 PERCENT: ORDERED EFF. RATE	(671,610)	(12,896,763)	(13,568,373)	7,362,281	(4,663,905)	(2,260,207)	(6,924,112)
263	ADD: TAX ADJ / TAX DEFICIENCY PAYMENT	65,221,919	0	65,221,919	(65,221,919)	0	0	0
264	PRIOR YEARS' TAX ADJUSTMENT	(58,582,917)	0	(58,582,917)	58,582,917	0	0	0
265								
266	TOTAL FEDERAL INCOME TAX	5,967,392	(12,896,763)	(6,929,371)	723,279	(4,663,905)	(2,260,207)	(6,924,112)

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
267	***TABLE 11-OREGON STATE INCOME TAX***							
268								
269	NET OPERATING INCOME BEFORE TAXES - OREGON	115,707,560	(3,616,412)	112,091,148	(22,010,195)	90,080,954	(6,891,926)	83,189,027
270								
271	ALLOWANCE FOR AFUDC	27,226,240	(27,226,240)	0	0	0	0	0
272	STATE INCOME TAX ADJUSTMENTS - PLANT	(104,566,571)	0	(104,566,571)	(11,731,411)	(116,297,982)	0	(116,297,982)
273	STATE INCOME TAX ADJUSTMENTS - OTHER	(33,909,170)	0	(33,909,170)	49,504,979	15,595,809	0	15,595,809
274	ADD: MFG DEDUCTION NOT ALLOWED	(229,000)	0	(229,000)	229,000	0	0	0
275								
276	TOTAL STATE INCOME TAX ADJUSTMENTS - OREGON	(111,478,501)	(27,226,240)	(138,704,741)	38,002,568	(100,702,173)	0	(100,702,173)
277								
278	INCOME SUBJECT TO OREGON TAX	4,229,059	(30,842,652)	(26,613,593)	15,992,373	(10,621,219)	(6,891,926)	(17,513,146)
279								
280	IERCO TAXABLE INCOME	5,286,622	0	5,286,622	4,913,378	10,200,000	0	10,200,000
281	BONUS DEPRECIATION & OTHER OREGON ADJ	78,338,493	0	78,338,493	(93,947,897)	(15,609,404)	0	(15,609,404)
282								
283	TOTAL STATE TAXABLE INCOME - OREGON	87,854,174	(30,842,652)	57,011,523	(73,042,146)	(16,030,623)	(6,891,926)	(22,922,550)
284								
285	OREGON TAX AT 0.3 PERCENT: ORDERED EFF. RATE	263,563	(92,528)	171,035	(219,126)	(48,092)	(20,676)	(68,768)
286	LESS: INVESTMENT TAX CREDIT	0	0	0		0	0	0
287								
288	STATE INCOME TAX ALLOWED - OREGON	263,563	(92,528)	171,035	(219,126)	(48,092)	(20,676)	(68,768)
289	ADD: TAX ADJ / TAX DEFICIENCY PAYMENT	384,597	0	384,597	(384,597)	0	0	0
290	PRIOR YEARS' TAX ADJUSTMENT	(355,236)	0	(355,236)	355,236	0	0	0
291								0
292	STATE INCOME TAX PAID - OREGON	292,924	(92,528)	200,396	(248,487)	(48,092)	(20,676)	(68,768)
293								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
294	***TABLE 12-IDAHO STATE INCOME TAX***							
295								
296	NET OPERATING INCOME BEFORE TAXES - IDAHO	115,707,560	(3,616,412)	112,091,148	(22,010,195)	90,080,954	(6,891,926)	83,189,027
297								
298	ALLOWANCE FOR AFUDC	27,226,240	(27,226,240)	0	0	0	0	0
299	STATE INCOME TAX ADJUSTMENTS - PLANT	(104,566,571)	0	(104,566,571)	(11,731,411)	(116,297,982)	0	(116,297,982)
300	STATE INCOME TAX ADJUSTMENTS - OTHER	(33,909,170)	0	(33,909,170)	49,504,979	15,595,809	0	15,595,809
301								
302	INCOME SUBJECT TO IDAHO TAX	4,458,059	(30,842,652)	(26,384,593)	15,763,373	(10,621,219)	(6,891,926)	(17,513,146)
303								
304	IERCO TAXABLE INCOME	5,286,622	0	5,286,622	4,913,378	10,200,000	0	10,200,000
305	BONUS DEPRECIATION ADJUSTMENT	79,922,617	0	79,922,617	16,654,406	96,577,023	0	96,577,023
306	TOTAL STATE TAXABLE INCOME - IDAHO	89,667,298	(30,842,652)	58,824,646	37,331,158	96,155,804	(6,891,926)	89,263,877
307								
308	IDAHO TAX AT 5.9 PERCENT: ORDERED EFF. RATE	5,290,371	(1,819,716)	3,470,654	2,202,538	5,673,192	(406,624)	5,266,569
309	LESS: INVESTMENT TAX CREDIT	0	0	0	2,920,457	2,920,457	0	2,920,457
310								
311	STATE INCOME TAX ALLOWED - IDAHO	5,290,371	(1,819,716)	3,470,654	(717,919)	2,752,735	(406,624)	2,346,112
312	ADD: TAX ADJ / TAX DEFICIENCY PAYMENT	7,563,734	0	7,563,734	(7,563,734)	0	0	0
313	PRIOR YEARS' TAX ADJUSTMENT	(10,091,052)	0	(10,091,052)	10,091,052	0	0	0
314	STATE INCOME TAX PAID - IDAHO	2,763,053	(1,819,716)	943,336	1,809,399	2,752,735	(406,624)	2,346,112
315								
316								
317	***OTHER STATE INCOME TAX***							
318	INCOME SUBJECT TO TAX	4,458,059	(30,842,652)	(26,384,593)	15,763,373	(10,621,219)	(6,891,926)	(17,513,146)
319								
320	IERCO TAXABLE INCOME	5,286,622	0	5,286,622	4,913,378	10,200,000	0	10,200,000
321	BONUS DEPRECIATION ADJUSTMENT	0	0	0	0	0	0	0
322	TOTAL TAXABLE INCOME-OTHER STATES	9,744,681	(30,842,652)	(21,097,971)	20,676,751	(421,219)	(6,891,926)	(7,313,146)
323								
324	OTHER TAX AT 0.1 PERCENT	9,745	(30,843)	(21,098)	20,677	(421)	(6,892)	(7,313)
325	ADD: TAX ADJ / TAX DEFICIENCY PAYMENT	128,199	0	0	0	0	0	0
326	PRIOR YEARS' TAX ADJUSTMENT	(136,694)	0	0	0	0	0	0
327	OTHER STATES' INCOME TAX PAID	1,250	(22,348)	(21,098)	20,677	(421)	(6,892)	(7,313)

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
328	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***							0
329	STEAM POWER GENERATION							0
330	OPERATION							0
331	500 / SUPERVISION & ENGINEERING	251,120		251,120		251,120		251,120
332	501 / FUEL	0		0		0		0
333	502 / STEAM EXPENSES			0				0
334	LABOR	0		0		0		0
335	OTHER	0		0		0		0
336								
337	505 / ELECTRIC EXPENSES			0				0
338	LABOR	0		0		0		0
339	OTHER	0		0		0		0
340								
341	506 / MISCELLANEOUS EXPENSES	25,816		25,816		25,816		25,816
342	507 / RENTS	0		0		0		0
343	STEAM OPERATION EXPENSES	276,936		276,936		276,936		276,936
344				0				0
345	MAINTENANCE			0				0
346	510 / SUPERVISION & ENGINEERING	0		0		0		0
347	511 / STRUCTURES	0		0		0		0
348	512 / BOILER PLANT			0				0
349	LABOR	0		0		0		0
350	OTHER	0		0		0		0
351	TOTAL ACCOUNT 512							
352	513 / ELECTRIC PLANT			0				0
353	LABOR	0		0		0		0
354	OTHER	0		0		0		0
355	TOTAL ACCOUNT 513							
356	514 / MISCELLANEOUS STEAM PLANT	0		0		0		0
357	STEAM MAINTENANCE EXPENSES	0		0		0		0
358	TOTAL STEAM GENERATION EXPENSES	276,936		276,936		276,936	0	276,936
359				0				0

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
360	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***			0				0
361	HYDRAULIC POWER GENERATION			0				0
362	OPERATION			0				0
363	535 / SUPERVISION & ENGINEERING	4,138,379		4,138,379		4,138,379		4,138,379
364	536 / WATER FOR POWER	557,584		557,584		557,584		557,584
365	537 / HYDRAULIC EXPENSES	4,669,049		4,669,049		4,669,049		4,669,049
366	538 / ELECTRIC EXPENSES			0				0
367	LABOR	1,133,916		1,133,916		1,133,916		1,133,916
368	OTHER	0		0		0		0
369	TOTAL ACCOUNT 538			0				0
370	539 / MISCELLANEOUS EXPENSES	1,878,098		1,878,098		1,878,098		1,878,098
371	540 / RENTS	0		0		0		0
372	HYDRAULIC OPERATION EXPENSES	12,377,026		12,377,026		12,377,026		12,377,026
373				0				0
374	MAINTENANCE			0				0
375	541 / SUPERVISION & ENGINEERING	1,632,395		1,632,395		1,632,395		1,632,395
376	542 / STRUCTURES	715,498		715,498		715,498		715,498
377	543 / RESERVOIRS, DAMS & WATERWAYS	632,240		632,240		632,240		632,240
378	544 / ELECTRIC PLANT			0				0
379	LABOR	1,989,149		1,989,149		1,989,149		1,989,149
380	OTHER	0		0		0		0
381	TOTAL ACCOUNT 544	1,989,149		1,989,149		1,989,149		1,989,149
382	545 / MISCELLANEOUS HYDRAULIC PLANT	1,934,114		1,934,114		1,934,114		1,934,114
383	HYDRAULIC MAINTENANCE EXPENSES	6,903,396		6,903,396		6,903,396		6,903,396
384	TOTAL HYDRAULIC GENERATION EXPENSES	19,280,422		19,280,422		19,280,422		19,280,422

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
385	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***			0				0
386	OTHER POWER GENERATION			0				0
387	OPERATION			0				0
388	546 / SUPERVISION & ENGINEERING	286,810		286,810		286,810		286,810
389	547 / FUEL	0		0		0		0
390	548 / GENERATING EXPENSES			0				0
391	LABOR	327,712		327,712		327,712		327,712
392	OTHER	0		0		0		0
393	TOTAL ACCOUNT 548			0				0
394	549 / MISCELLANEOUS EXPENSES	323,105		323,105		323,105		323,105
395	550 / RENTS	0		0		0		0
396	OTHER POWER OPER EXPENSES	937,627		937,627		937,627		937,627
397				0				0
398	MAINTENANCE			0				0
399	551 / SUPERVISION & ENGINEERING	0		0		0		0
400	552 / STRUCTURES	127,875		127,875		127,875		127,875
401	553 / GENERATING & ELECTRIC PLANT			0				0
402	LABOR	88,691		88,691		88,691		88,691
403	OTHER			0				0
404	TOTAL ACCOUNT 553			0				0
405	554 / MISCELLANEOUS EXPENSES	355,196		355,196		355,196		355,196
406	OTHER POWER MAINT EXPENSES	571,762		571,762		571,762		571,762
407	TOTAL OTHER POWER GENERATION EXP	1,509,389		1,509,389		1,509,389		1,509,389
408				0				0
409	OTHER POWER SUPPLY EXPENSE			0				0
410	555.0 / PURCHASED POWER	0		0		0		0
411	555.1 / COGENERATION & SMALL POWER PROD			0				0
412	CAPACITY RELATED	0		0		0		0
413	ENERGY RELATED	0		0		0		0
414	TOTAL 555.1/CSPP							
415	555/TOTAL							
416	556 / LOAD CONTROL & DISPATCHING EXPENSES	0		0		0		0
417	557 / OTHER EXPENSES	1,969,127		1,969,127		1,969,127		1,969,127
418	TOTAL OTHER POWER SUPPLY EXPENSES	1,969,127		1,969,127		1,969,127		1,969,127
419				0				0
420	TOTAL PRODUCTION EXPENSES	23,035,874		23,035,874		23,035,874		23,035,874

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
421	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***			0				0
422	TRANSMISSION EXPENSES			0				0
423	OPERATION			0				0
424	560 / SUPERVISION & ENGINEERING	1,876,009		1,876,009		1,876,009		1,876,009
425	561 / LOAD DISPATCHING	2,606,404		2,606,404		2,606,404		2,606,404
426	562 / STATION EXPENSES	1,406,018		1,406,018		1,406,018		1,406,018
427	563 / OVERHEAD LINE EXPENSES	325,684		325,684		325,684		325,684
428	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	0		0		0		0
429	566 / MISCELLANEOUS EXPENSES	29,797		29,797		29,797		29,797
430	567 / RENTS	0		0		0		0
431	TOTAL TRANSMISSION OPERATION	6,243,912		6,243,912		6,243,912		6,243,912
432				0				0
433	MAINTENANCE			0				0
434	568 / SUPERVISION & ENGINEERING	128,017		128,017		128,017		128,017
435	569 / STRUCTURES	318,561		318,561		318,561		318,561
436	570 / STATION EQUIPMENT	1,938,436		1,938,436		1,938,436		1,938,436
437	571 / OVERHEAD LINES	835,101		835,101		835,101		835,101
438	573 / MISCELLANEOUS PLANT	0		0		0		0
439	TOTAL TRANSMISSION MAINTENANCE	3,220,115		3,220,115		3,220,115		3,220,115
440				0				0
441	TOTAL TRANSMISSION EXPENSES	9,464,027		9,464,027		9,464,027		9,464,027

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
442	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***			0				0
443	DISTRIBUTION EXPENSES			0				0
444	OPERATION			0				0
445	580 / SUPERVISION & ENGINEERING	2,826,824		2,826,824		2,826,824		2,826,824
446	581 / LOAD DISPATCHING	2,940,004		2,940,004		2,940,004		2,940,004
447	582 / STATION EXPENSES	841,162		841,162		841,162		841,162
448	583 / OVERHEAD LINE EXPENSES	2,454,103		2,454,103		2,454,103		2,454,103
449	584 / UNDERGROUND LINE EXPENSES	640,628		640,628		640,628		640,628
450	585 / STREET LIGHTING & SIGNAL SYSTEMS	63,072		63,072		63,072		63,072
451	586 / METER EXPENSES	3,037,247		3,037,247		3,037,247		3,037,247
452	587 / CUSTOMER INSTALLATIONS EXPENSE	1,047,805		1,047,805		1,047,805		1,047,805
453	588 / MISCELLANEOUS EXPENSES	3,092,742		3,092,742		3,092,742		3,092,742
454	589 / RENTS	107		107		107		107
455	TOTAL DISTRIBUTION OPERATION	16,943,694		16,943,694		16,943,694		16,943,694
456				0				0
457	MAINTENANCE			0				0
458	590 / SUPERVISION & ENGINEERING	303,700		303,700		303,700		303,700
459	591 / STRUCTURES	0		0		0		0
460	592 / STATION EQUIPMENT	2,190,252		2,190,252		2,190,252		2,190,252
461	593 / OVERHEAD LINES	5,129,594		5,129,594		5,129,594		5,129,594
462	594 / UNDERGROUND LINES	645,314		645,314		645,314		645,314
463	595 / LINE TRANSFORMERS	24,820		24,820		24,820		24,820
464	596 / STREET LIGHTING & SIGNAL SYSTEMS	327,168		327,168		327,168		327,168
465	597 / METERS	511,932		511,932		511,932		511,932
466	598 / MISCELLANEOUS PLANT	107,136		107,136		107,136		107,136
467	TOTAL DISTRIBUTION MAINTENANCE	9,239,916		9,239,916		9,239,916		9,239,916
468	TOTAL DISTRIBUTION EXPENSES	26,183,610		26,183,610		26,183,610		26,183,610
469				0				0
470	CUSTOMER ACCOUNTING EXPENSES			0				0
471	901 / SUPERVISION	359,608		359,608		359,608		359,608
472	902 / METER READING	2,269,828		2,269,828		2,269,828		2,269,828
473	903 / CUSTOMER RECORDS & COLLECTIONS	6,906,743		6,906,743		6,906,743		6,906,743
474	904 / UNCOLLECTIBLE ACCOUNTS	0		0		0		0
475	905 / MISC EXPENSES	0		0		0		0
476	TOTAL CUSTOMER ACCOUNTING EXPENSES	9,536,179		9,536,179		9,536,179		9,536,179
477				0				0
478	CUSTOMER SERVICES & INFORMATION EXPENSES			0				0
479	907 / SUPERVISION	279,335		279,335		279,335		279,335
480	908 / CUSTOMER ASSISTANCE	3,632,577		3,632,577		3,632,577		3,632,577
481	908 / DSM RIDER	0		0		0		0
482	909 / INFORMATION & INSTRUCTIONAL	0		0		0		0
483	910 / MISCELLANEOUS EXPENSES	508,430		508,430		508,430		508,430
484	TOTAL CUST SERV & INFORMATN EXPENSES	4,420,342		4,420,342		4,420,342		4,420,342

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

1	2	3	4	5	6	7	8	9
2		2010	2010 Actual	2010	Forecast	2011 Unadjusted	Annualizing	2011
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
485	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***			0				0
486	ADMINISTRATIVE & GENERAL EXPENSES			0				0
487	920 / ADMINISTRATIVE & GENERAL SALARIES	40,893,203		40,893,203		40,893,203		40,893,203
488	921 / OFFICE SUPPLIES	194,129		194,129		194,129		194,129
489	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	0		0		0		0
490	923 / OUTSIDE SERVICES	0		0		0		0
491	924 / PROPERTY INSURANCE			0				0
492	PRODUCTION - STEAM	0		0		0		0
493	ALL RISK & MISCELLANEOUS	231,444		231,444		231,444		231,444
494	TOTAL ACCOUNT 924							
495	925 / INJURIES & DAMAGES	162,751		162,751		162,751		162,751
496	926 / EMPLOYEE PENSIONS & BENEFITS	0		0		0		0
497	927 / FRANCHISE REQUIREMENTS	0		0		0		0
498	928 / REGULATORY COMMISSION EXPENSES							
499	928.101 / FERC ADMIN ASSESS & SECURITIES							
500	CAPACITY RELATED	0		0		0		0
501	ENERGY RELATED	0		0		0		0
502	928.101 / FERC ORDER 472	0		0		0		0
503	928.101 / FERC MISCELLANIOUS	0		0		0		0
504	928.102 FERC RATE CASE	0		0		0		0
505	928.104 / FERC OREGON HYDRO	0		0		0		0
506	SEC EXPENSES	0		0		0		0
507	928.202 / IDAHO PUC -RATE CASE	0		0		0		0
508	928.203 / IDAHO PUC - OTHER	0		0		0		0
509	928.301 / OREGON PUC - FILING FEES	0		0		0		0
510	928.302 / OREGON PUC - RATE CASE	0		0		0		0
511	928.303 / OREGON PUC - OTHER	0		0		0		0
512	IPC/PUC JSS TRUE-UP ADJ	0		0		0		0
513	TOTAL ACCOUNT 928							
514	929 / DUPLICATE CHARGES	0		0		0		0
515	930.1 / GENERAL ADVERTISING	0		0		0		0
516	930.2 / MISCELLANEOUS EXPENSES	0		0		0		0
517	931 / RENTS	132,751		132,751		132,751		132,751
518	TOTAL ADM & GEN OPERATION	41,614,278		41,614,278		41,614,278	0	41,614,278
519	PLUS:			0				0
520	935 / GENERAL PLANT MAINTENANCE	1,072,390		1,072,390		1,072,390		1,072,390
521	416 / MERCHANDISING EXPENSE	0		0		0		0
522	TOTAL OPER & MAINT EXPENSES	115,326,700		115,326,700		115,326,700	0	115,326,700

Idaho Power/905
Witness: Kelley Noe

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Kelley Noe
Jurisdictional Separation Study – Oregon Revenue Requirement

July 29, 2011

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
4	***SUMMARY OF RESULTS***				
5	**RATE OF RETURN UNDER PRESENT RATES**				
6	TOTAL COMBINED RATE BASE		2,499,296,901	**121,853,764**	*2,377,443,137*
7					
8	OPERATING REVENUES				
9	FIRM JURISDICTIONAL SALES		852,039,782	**39,873,591**	*812,166,191*
10	HOKU 1ST BLOCK ENERGY SALES		23,981,399	**1,109,655**	*22,871,744*
11	SYSTEM OPPORTUNITY SALES		82,876,756	**3,834,832**	*79,041,924*
12	OTHER OPERATING REVENUES		44,555,238	**1,958,872**	*42,596,366*
13	TOTAL OPERATING REVENUES		1,003,453,175	**46,776,951**	*956,676,224*
14	OPERATING EXPENSES				
15	OPERATION & MAINTENANCE EXPENSES		684,766,241	**31,790,864**	*652,975,377*
16	DEPRECIATION EXPENSE		116,113,901	**5,098,532**	*111,015,369*
17	AMORTIZATION OF LIMITED TERM PLANT		7,208,808	**331,470**	*6,877,337*
18	TAXES OTHER THAN INCOME		27,632,526	**2,029,747**	*25,602,779*
19	REGULATORY DEBITS/CREDITS		27,757	**27,757**	*0*
20	PROVISION FOR DEFERRED INCOME TAXES		39,576,457	**1,917,244**	*37,659,213*
21	INVESTMENT TAX CREDIT ADJUSTMENT		(470,989)	**(22,594)**	*(448,395)*
22	FEDERAL INCOME TAXES		(6,924,112)	**(549,346)**	*(6,374,766)*
23	STATE INCOME TAXES		2,270,031	**66,007**	*2,204,023*
24	TOTAL OPERATING EXPENSES		870,200,619	**40,689,682**	*829,510,937*
25	OPERATING INCOME		133,252,556	**6,087,268**	*127,165,287*
26	ADD: IERCO OPERATING INCOME		6,629,998	**306,780**	*6,323,218*
27	CONSOLIDATED OPERATING INCOME		139,882,554	**6,394,048**	*133,488,506*
28	RATE OF RETURN UNDER PRESENT RATES		5.60%	**5.25%**	*5.61%*
29					
30	**DEVELOPMENT OF REVENUE REQUIREMENTS**				
31	RATE OF RETURN @ 10.5% ROE		8.170%	**8.170%**	*8.170%*
32					
33	RETURN		204,192,557	**9,955,453**	*194,237,104*
34	EARNINGS DEFICIENCY		64,310,003	**3,561,404**	*60,748,599*
35	ADD: CWIP (HELLS CANYON RELICENSING)	D10	0	**0**	*0*
36	DEFICIENCY WITH CWIP		64,310,003	**3,561,404**	*60,748,599*
37					
38	NET-TO-GROSS TAX MULTIPLIER		1.642	**1.642**	*1.642*
39	**REVENUE DEFICIENCY**		105,597,025	**5,847,826**	*99,749,199*
40					
41	FIRM JURISDICTIONAL REVENUES		876,021,181	**39,873,591**	*835,037,935*
42	PERCENT INCREASE REQUIRED		12.05%	**14.67%**	*11.95%*
43					
44	SALES AND WHEELING REVENUES REQUIRED		981,618,206	**45,721,417**	*934,787,134*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
45	***SUMMARY OF RESULTS***				
46	**DEVELOPMENT OF RATE BASE COMPONENTS**				
47	ELECTRIC PLANT IN SERVICE				
48	INTANGIBLE PLANT		54,520,675	**2,506,932**	*52,013,743*
49	PRODUCTION PLANT		1,816,031,496	**78,698,067**	*1,737,333,429*
50	TRANSMISSION PLANT		869,772,561	**37,783,895**	*831,988,666*
51	DISTRIBUTION PLANT		1,424,822,264	**80,708,809**	*1,344,113,455*
52	GENERAL PLANT		263,694,048	**12,649,662**	*251,044,386*
53	TOTAL ELECTRIC PLANT IN SERVICE		4,428,841,043	**212,347,364**	*4,216,493,679*
54	LESS: ACCUM PROVISION FOR DEPRECIATION		1,789,401,601	**85,382,820**	*1,704,018,781*
55	AMORT OF OTHER UTILITY PLANT		21,305,872	**939,189**	*20,366,682*
56	NET ELECTRIC PLANT IN SERVICE		2,618,133,570	**126,025,354**	*2,492,108,216*
57	LESS: CUSTOMER ADV FOR CONSTRUCTION		17,261,533	**20,254**	*17,241,279*
58	LESS: ACCUM DEFERRED INCOME TAXES		292,036,047	**14,331,059**	*277,704,988*
59	ADD : PLT HLD FOR FUTURE+ACQUIS ADJ		(13,254)	**0**	*(13,254)*
60	ADD : WORKING CAPITAL		99,174,902	**4,653,120**	*94,521,781*
61	ADD : CONSERVATION+OTHER DFRD PROG.		2,303,419	**1,408,630**	*894,789*
62	ADD : SUBSIDIARY RATE BASE		88,995,844	**4,117,971**	*84,877,873*
63	TOTAL COMBINED RATE BASE		2,499,296,901	**121,853,764**	*2,377,443,137*
64					
65	**DEVELOPMENT OF NET INCOME COMPONENTS**				
66	OPERATING REVENUES				
67	SALES REVENUES		958,897,937	**44,818,078**	*914,079,859*
68	OTHER OPERATING REVENUES		44,555,238	**1,958,872**	*42,596,366*
69	TOTAL OPERATING REVENUES		1,003,453,175	**46,776,951**	*956,676,224*
70	OPERATING EXPENSES				
71	OPERATION & MAINTENANCE EXPENSES		684,766,241	**31,790,864**	*652,975,377*
72	DEPRECIATION EXPENSE		116,113,901	**5,098,532**	*111,015,369*
73	AMORTIZATION OF LIMITED TERM PLANT		7,208,808	**331,470**	*6,877,337*
74	TAXES OTHER THAN INCOME		27,632,526	**2,029,747**	*25,602,779*
75	REGULATORY DEBITS/CREDITS		27,757	**27,757**	*0*
76	PROVISION FOR DEFERRED INCOME TAXES		39,576,457	**1,917,244**	*37,659,213*
77	INVESTMENT TAX CREDIT ADJUSTMENT		(470,989)	**(22,594)**	*(448,395)*
78	FEDERAL INCOME TAXES		(6,924,112)	**(549,346)**	*(6,374,766)*
79	STATE INCOME TAXES		2,270,031	**66,007**	*2,204,023*
80	TOTAL OPERATING EXPENSES		870,200,619	**40,689,682**	*829,510,937*
81	OPERATING INCOME		133,252,556	**6,087,268**	*127,165,287*
82	ADD: IERCO OPERATING INCOME	E10	6,629,998	**306,780**	*6,323,218*
83	CONSOLIDATED OPERATING INCOME		139,882,554	**6,394,048**	*133,488,506*
84					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
107	***TABLE 1-ELECTRIC PLANT IN SERVICE***				
108	INTANGIBLE PLANT				
109	301 - ORGANIZATION	P101P	5,703	**274**	*5,429*
110	302 - FRANCHISES & CONSENTS	D10	23,400,154	**1,014,050**	*22,386,104*
111	303 - MISCELLANEOUS	P101P	31,114,818	**1,492,608**	*29,622,210*
112					
113	TOTAL INTANGIBLE PLANT		54,520,675	**2,506,932**	*52,013,743*
114					
115	PRODUCTION PLANT				
116	310-316 / STEAM PRODUCTION	D10	937,956,085	**40,646,504**	*897,309,582*
117	330-336 / HYDRAULIC PRODUCTION	D10	702,810,444	**30,456,423**	*672,354,021*
118	340-346 / OTHER PRODUCTION	D10	175,264,966	**7,595,140**	*167,669,826*
119					
120	TOTAL PRODUCTION PLANT		1,816,031,496	**78,698,067**	*1,737,333,429*
121					
122	TRANSMISSION PLANT				
123	350 / LAND & LAND RIGHTS - SYSTEM SERVICE	D11	34,128,139	**1,478,949**	*32,649,189*
124	TRANSMISSION RETAIL	D12	125,006	**5,417**	*119,589*
125	DIRECT ASSIGNMENT	DA350	792	**792**	*0*
126	TOTAL ACCOUNT 350		34,253,937	**1,485,158**	*32,768,778*
127					
128	352 / STRUCTURES & IMPROVEMENTS - SYSTEM SERV	D11	54,683,468	**2,369,718**	*52,313,749*
129	TRANSMISSION RETAIL	D12	1,681,193	**72,855**	*1,608,338*
130	DIRECT ASSIGNMENT	DA352	658	**658**	*0*
131	TOTAL ACCOUNT 352		56,365,319	**2,443,231**	*53,922,088*
132					
133	353 / STATION EQUIPMENT - SYSTEM SERVICE	D11	335,775,911	**14,550,912**	*321,224,998*
134	TRANSMISSION RETAIL	D12	20,066,422	**869,582**	*19,196,840*
135	DIRECT ASSIGNMENT	DA353	74,044	**36,494**	*37,550*
136	TOTAL ACCOUNT 353		355,916,377	**15,456,988**	*340,459,388*
137					
138	354 / TOWERS & FIXTURES - SYSTEM SERVICE	D11	147,452,164	**6,389,867**	*141,062,297*
139	TRANSMISSION RETAIL	D12	0	**0**	*0*
140	DIRECT ASSIGNMENT	DA354	0	**0**	*0*
141	TOTAL ACCOUNT 354		147,452,164	**6,389,867**	*141,062,297*
142					
143	355 / POLES & FIXTURES - SYSTEM SERVICE	D11	102,342,273	**4,435,022**	*97,907,251*
144	TRANSMISSION RETAIL	D12	35,858	**1,554**	*34,304*
145	DIRECT ASSIGNMENT	DA355	34,064	**33,630**	*434*
146	TOTAL ACCOUNT 355		102,412,195	**4,470,206**	*97,941,990*
147					
148	356 / OVERHEAD CONDUCTORS & DEVICES - SYSTEM S	D11	172,866,106	**7,491,185**	*165,374,920*
149	TRANSMISSION RETAIL	D12	159,892	**6,929**	*152,963*
150	DIRECT ASSIGNMENT	DA356	28,221	**26,534**	*1,687*
151	TOTAL ACCOUNT 356		173,054,219	**7,524,648**	*165,529,570*
152					
153	359 / ROADS & TRAILS - SYSTEM SERVICE	D11	318,351	**13,796**	*304,555*
154	TRANSMISSION RETAIL	D12	0	**0**	*0*
155	DIRECT ASSIGNMENT	DA359	0	**0**	*0*
156	TOTAL ACCOUNT 359		318,351	**13,796**	*304,555*
157					
158	TOTAL TRANSMISSION PLANT		869,772,561	**37,783,895**	*831,988,666*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
159	***TABLE 1-ELECTRIC PLANT IN SERVICE***				
160					
161	DISTRIBUTION PLANT				
162	360 / LAND & LAND RIGHTS - SYSTEM SERVICE	DA360	4,745,190	**136,079**	*4,609,110*
163	PLUS: ADJUSTMENT FOR CIAC	DA360C	89,946	**305**	*89,641*
164	DISTRIBUTION PLANT + CIAC		4,835,136	**136,384**	*4,698,751*
165					
166	361 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	DA361	30,780,615	**1,199,046**	*29,581,569*
167	PLUS: ADJUSTMENT FOR CIAC	DA361C	6,129,068	**30,890**	*6,098,178*
168	DISTRIBUTION PLANT + CIAC		36,909,683	**1,229,936**	*35,679,747*
169					
170	362 / STATION EQUIPMENT - SYSTEM SERVICE	DA362	195,725,125	**6,511,152**	*189,213,972*
171	PLUS: ADJUSTMENT FOR CIAC	DA362C	24,743,557	**91,357**	*24,652,200*
172	DISTRIBUTION PLANT + CIAC		220,468,682	**6,602,509**	*213,866,172*
173					
174	364 / POLES, TOWERS & FIXTURES	DA364	229,145,727	**16,898,073**	*212,247,654*
175	365 / OVERHEAD CONDUCTORS & DEVICES	DA365	123,244,038	**7,413,400**	*115,830,638*
176	366 / UNDERGROUND CONDUIT	DA366	49,340,813	**690,605**	*48,650,209*
177	367 / UNDERGROUND CONDUCTORS & DEVICES	DA367	195,482,555	**3,265,467**	*192,217,088*
178	368 / LINE TRANSFORMERS	DA368	420,987,096	**38,182,883**	*382,804,213*
179	369 / SERVICES	DA369	58,328,068	**2,993,636**	*55,334,432*
180	370 / ALL OTHER METERS	DA370	14,811,250	**1,046,093**	*13,765,158*
181	AMI	DA370A	53,969,519	**1,918,616**	*52,050,903*
182	PRE-AMI (OREGON)	CODA	0	**0**	*0*
183	PRE-AMI (IDAHO)	CIDA	41,108,636	**0**	*41,108,636*
184	TOTAL ACCOUNT 370		109,889,405	**2,964,709**	*106,924,696*
185	371 / INSTALLATIONS ON CUSTOMER PREMISES	DA371	2,776,999	**237,207**	*2,539,792*
186	373 / STREET LIGHTING SYSTEMS	DA373	4,376,633	**216,551**	*4,160,082*
187					
188	TOTAL DISTRIBUTION PLANT (without CIAC)		1,424,822,264	**80,708,809**	*1,344,113,455*
189					
190	GENERAL PLANT				
191	389 / LAND & LAND RIGHTS	PTD	11,796,672	**565,898**	*11,230,774*
192	390 / STRUCTURES & IMPROVEMENTS	PTD	83,159,345	**3,989,235**	*79,170,110*
193	391 / OFFICE FURNITURE & EQUIPMENT	PTD	42,455,976	**2,036,655**	*40,419,321*
194	392 / TRANSPORTATION EQUIPMENT	PTD	60,415,459	**2,898,189**	*57,517,270*
195	393 / STORES EQUIPMENT	PTD	1,507,622	**72,322**	*1,435,300*
196	394 / TOOLS, SHOP & GARAGE EQUIPMENT	PTD	5,714,737	**274,142**	*5,440,596*
197	395 / LABORATORY EQUIPMENT	PTD	12,315,358	**590,780**	*11,724,578*
198	396 / POWER OPERATED EQUIPMENT	PTD	9,796,782	**469,961**	*9,326,821*
199	397 / COMMUNICATIONS EQUIPMENT	PTD	31,390,116	**1,505,815**	*29,884,301*
200	398 / MISCELLANEOUS EQUIPMENT	PTD	5,141,981	**246,666**	*4,895,315*
201					
202	TOTAL GENERAL PLANT		263,694,048	**12,649,662**	*251,044,386*
203					
204	TOTAL ELECTRIC PLANT IN SERVICE (without CIAC)		4,428,841,043	**212,347,364**	*4,216,493,679*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
205	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***				
206					
207	PRODUCTION PLANT				
208	310-316 / STEAM PRODUCTION	L 116	520,071,289	**22,537,387**	*497,533,902*
209	330-336 / HYDRAULIC PRODUCTION	L 117	345,406,476	**14,968,255**	*330,438,221*
210	340-346 / OTHER PRODUCTION	L 118	30,834,243	**1,336,208**	*29,498,036*
211	TOTAL PRODUCTION PLANT		896,312,008	**38,841,850**	*857,470,159*
212					
213	TRANSMISSION PLANT				
214	350 / LAND & LAND RIGHTS	L 126	5,653,832	**245,135**	*5,408,697*
215	352 / STRUCTURES & IMPROVEMENTS	L 131	20,989,256	**909,808**	*20,079,448*
216	353 / STATION EQUIPMENT	L 136	98,514,383	**4,278,352**	*94,236,031*
217	354 / TOWERS & FIXTURES	L 141	41,245,823	**1,787,395**	*39,458,427*
218	355 / POLES & FIXTURES	L 146	51,527,571	**2,249,135**	*49,278,436*
219	356 / OVERHEAD CONDUCTORS & DEVICES	L 151	53,587,773	**2,330,074**	*51,257,699*
220	359 / ROADS & TRAILS	L 156	258,250	**11,191**	*247,059*
221	TOTAL TRANSMISSION PLANT		271,776,889	**11,811,091**	*259,965,798*
222					
223	DISTRIBUTION PLANT				
224	360 / LAND & LAND RIGHTS	L 162	0	**0**	*0*
225	361 / STRUCTURES & IMPROVEMENTS	L 166	8,257,684	**321,675**	*7,936,009*
226	362 / STATION EQUIPMENT	L 170	44,910,718	**1,494,037**	*43,416,681*
227	364 / POLES, TOWERS & FIXTURES	L 174	112,472,074	**8,294,116**	*104,177,958*
228	365 / OVERHEAD CONDUCTORS & DEVICES	L 175	43,287,681	**2,603,849**	*40,683,832*
229	366 / UNDERGROUND CONDUIT	L 176	12,364,028	**173,055**	*12,190,973*
230	367 / UNDERGROUND CONDUCTORS & DEVICES	L 177	68,968,474	**1,152,094**	*67,816,380*
231	368 / LINE TRANSFORMERS	L 178	140,743,262	**12,765,198**	*127,978,064*
232	369 / SERVICES	L 179	37,256,094	**1,912,136**	*35,343,959*
233	370 / ALL OTHER METERS	L 180	5,500,778	**388,510**	*5,112,268*
234	AMI	L 181	4,524,545	**160,848**	*4,363,698*
235	PRE-AMI (OREGON)	L 182	0	**0**	*0*
236	PRE-AMI (IDAHO)	L 183	30,679,225	**0**	*30,679,225*
237	371 / INSTALLATIONS ON CUSTOMER PREMISES	L 185	2,231,210	**190,587**	*2,040,623*
238	373 / STREET LIGHTING SYSTEMS	L 186	3,312,129	**163,881**	*3,148,249*
239	TOTAL DISTRIBUTION PLANT		514,507,903	**29,619,984**	*484,887,919*
240					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
241	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***				
242					
243	GENERAL PLANT				
244	389 / LAND & LAND RIGHTS	L 191	0	**0**	*0*
245	390 / STRUCTURES & IMPROVEMENTS	L 192	22,446,276	**1,076,770**	*21,369,507*
246	391 / OFFICE FURNITURE & EQUIPMENT	L 193	26,389,318	**1,265,921**	*25,123,396*
247	392 / TRANSPORTATION EQUIPMENT	L 194	19,565,405	**938,572**	*18,626,834*
248	393 / STORES EQUIPMENT	L 195	541,617	**25,982**	*515,635*
249	394 / TOOLS, SHOP & GARAGE EQUIPMENT	L 196	2,573,048	**123,432**	*2,449,616*
250	395 / LABORATORY EQUIPMENT	L 197	5,856,989	**280,965**	*5,576,023*
251	396 / POWER OPERATED EQUIPMENT	L 198	3,954,543	**189,703**	*3,764,840*
252	397 / COMMUNICATIONS EQUIPMENT	L 199	16,455,048	**789,365**	*15,665,683*
253	398 / MISCELLANEOUS EQUIPMENT	L 200	2,169,571	**104,076**	*2,065,495*
254	TOTAL GENERAL PLANT		99,951,816	**4,794,786**	*95,157,029*
255					
256	AMORTIZATION OF DISALLOWED COSTS	L 113	6,852,985	**315,109**	*6,537,876*
257					
258	TOTAL ACCUM PROVISION DEPRECIATION		1,789,401,601	**85,382,820**	*1,704,018,781*
259					
260	AMORTIZATION OF OTHER UTILITY PLANT				
261	INTANGIBLE PLANT	L 113	6,007,098	**276,214**	*5,730,884*
262	HYDRAULIC PRODUCTION	L 117	15,298,774	**662,975**	*14,635,799*
263					
264	TOTAL AMORT OF OTHER UTILITY PLANT		21,305,872	**939,189**	*20,366,682*
265					
266	TOTAL ACCUM PROVISION FOR DEPR				
267	& AMORTIZATION OF OTHER UTILITY PLANT		1,810,707,473	**86,322,010**	*1,724,385,463*
268					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
269	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***				
270					
271	NET ELECTRIC PLANT IN SERVICE		2,618,133,570	**126,025,354**	*2,492,108,216*
272	LESS:				
273	252 CUSTOMER ADVANCES FOR CONSTRUCTION				
274	POWER SUPPLY	D10	0	**0**	*0*
275	OTHER	DA252	17,261,533	**20,254**	*17,241,279*
276	TOTAL CUSTOMER ADV FOR CONSTRUCTION		17,261,533	**20,254**	*17,241,279*
277					
278	ACCUMULATED DEFERRED INCOME TAXES				
279	190 / ACCUMULATED DEFERRED INCOME TAXES				
280	CUSTOMER ADVANCES FOR CONSTUCTION	DA252	(6,119,047)	**(7,180)**	*(6,111,867)*
281	OTHER	LABOR	(15,974,945)	**(730,887)**	*(15,244,058)*
282	TOTAL ACCOUNT 190		(22,093,992)	**(738,067)**	*(21,355,925)*
283	281 / ACCELERATED AMORTIZATION	P101P	0	**0**	*0*
284	282 / OTHER PROPERTY	P101P	294,576,289	**14,131,113**	*280,445,176*
285	283 / OTHER	P101P	19,553,750	**938,013**	*18,615,737*
286	TOTAL ACCUM DEFERRED INCOME TAXES		292,036,047	**14,331,059**	*277,704,988*
287					
288	NET ELECTRIC PLANT IN SERVICE		2,308,835,990	**111,674,042**	*2,197,161,949*
289	ADD:				
290	WORKING CAPITAL				
291	151 / FUEL INVENTORY	E10	25,531,502	**1,181,381**	*24,350,121*
292	154 & 163 / PLANT MATERIALS & SUPPLIES				
293	PRODUCTION - GENERAL	L 120	14,111,733	**611,535**	*13,500,198*
294	TRANSMISSION - GENERAL	L 158	13,113,870	**569,681**	*12,544,189*
295	DISTRIBUTION - GENERAL	L 188+CIAC	14,068,033	**781,117**	*13,286,916*
296	OTHER - UNCLASSIFIED	L 204	4,959,114	**237,772**	*4,721,342*
297	TOTAL ACCOUNT 154 & 163		46,252,750	**2,200,105**	*44,052,645*
298	165 / PREPAID ITEMS				
299	AD VALOREM TAXES	L 688	0	**0**	*0*
300	OTHER PROD-RELATED PREPAYMENTS	D10	0	**0**	*0*
301	INSURANCE	L 120	0	**0**	*0*
302	PENSION EXPENSE	L 1020	0	**0**	*0*
303	PREPAID RETIREE BENEFITS	L 1020	0	**0**	*0*
304	MISCELLANEOUS PREPAYMENTS	P101P	0	**0**	*0*
305	TOTAL ACCOUNT 165		0	**0**	*0*
306	WORKING CASH ALLOWANCE	L 608	27,390,650	**1,271,635**	*26,119,015*
307					
308	TOTAL WORKING CAPITAL		99,174,902	**4,653,120**	*94,521,781*
309					
310	NET ELECTRIC PLANT IN SERVICE		2,408,010,892	**116,327,162**	*2,291,683,730*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
311	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***				
312					
313	NET ELECTRIC PLANT IN SERVICE		2,408,010,892	**116,327,162**	*2,291,683,730*
314	ADD:				
315	105 / PLANT HELD FOR FUTURE USE				
316	HYDRAULIC PRODUCTION	L 117	0	**0**	*0*
317	TRANS LAND & LAND RIGHTS	L 126	0	**0**	*0*
318	TRANS STRUCTURES & IMPROVEMENTS	L 131	0	**0**	*0*
319	TRANS STATION EQUIPMENT	L 136	0	**0**	*0*
320	DIST LAND & LAND RIGHTS	L 164	0	**0**	*0*
321	DIST STRUCTURES & IMPROVEMENTS	L 168	0	**0**	*0*
322	GEN LAND & LAND RIGHTS	L 191	0	**0**	*0*
323	GEN STRUCTURES & IMPROVEMENTS	L 192	0	**0**	*0*
324	TRANSPORTATION EQUIPMENT	L 194	0	**0**	*0*
325	TOTAL PLANT HELD FOR FUTURE USE		0	**0**	*0*
326					
327	114/115 - PRAIRIE ACQUISITION ADJUSMENT (ACCOUN	CIDA	(13,254)	**0**	*(13,254)*
328					
329	DEFERRED PROGRAMS:				
330	182 / CONSERVATION PROGRAMS				
331	IDAHO DEFERRED CONSERVATION PROGRAMS	CIDA	0	**0**	*0*
332	OREGON DEFERRED CONSERVATION PROGRAMS	CODA	0	**0**	*0*
333	TOTAL CONSERVATION PROGRAMS		0	**0**	*0*
334	182 / MISC. OTHER REGULATORY ASSETS				
335	OTHER DEFERRED	D10	0	**0**	*0*
336	CUB FUND GRAND - (OPUC ORDER 10-406	CODA	0	**0**	*0*
337	ZGA ARCHITECTS & PLANNERS	LABOR	0	**0**	*0*
338	PENSION DEFERRAL - OPUC ORDER 10-064	CODA	1,323,161	**1,323,161**	*0*
339	INTERVENOR FUNDING	CIDA	0	**0**	*0*
340	GRID WEST - OPUC ORDER 06-483	CODA	44,937	**44,937**	*0*
341	GRID WEST - FERC	D11	111,728	**4,842**	*106,886*
342	TOTAL OTHER REGULATORY ASSETS		1,479,826	**1,372,940**	*106,886*
343	186 / MISC. OTHER DEFERRED PROGRAMS				
344	AM. FALLS BOND REFINANCING	D10	823,593	**35,691**	*787,902*
345	TOTAL DEFERRED PROGRAMS		2,303,419	**1,408,630**	*894,789*
346					
347	DEVELOPMENT OF IERCO RATE BASE				
348	INVESTMENT IN IERCO	E10	75,106,349	**3,475,284**	*71,631,065*
349	PREPAID COAL ROYALTIES	E10	1,396,225	**64,605**	*1,331,620*
350	NOTES PAYABLE TO/RECEIVABLE FROM SUBSIDIARY	E10	12,493,270	**578,082**	*11,915,188*
351	TOTAL SUBSIDIARY RATE BASE		88,995,844	**4,117,971**	*84,877,873*
352					
353	TOTAL COMBINED RATE BASE		2,499,296,901	**121,853,764**	*2,377,443,137*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
354	***TABLE 4-OPERATING REVENUES***				
355	FIRM ENERGY SALES				
356	440-448 / RETAIL	RETREV	852,039,782	**39,873,591**	*812,166,191*
357	442 / HOKU BLOCK 1 ENERGY	E10	23,981,399	**1,109,655**	*22,871,744*
358	447 / FIRM SALES FOR RESALE	RESREV	0	**0**	*0*
359	447 / SYSTEM OPPORTUNITY SALES	E10	82,876,756	**3,834,832**	*79,041,924*
360	447 / SYSTEM OPPORTUNITY LOSS REVENUES	E10	0	**0**	*0*
361	TOTAL SALES OF ELECTRICITY		958,897,937	**44,818,078**	*914,079,859*
362					
363	OTHER OPERATING REVENUES				
364	415 / MERCHANDISING REVENUES	D60	784,615	**32,165**	*752,450*
365					
366	449 / OATT TARIFF REFUND				
367	NETWORK	D11	0	**0**	*0*
368	POINT-TO-POINT	D11	0	**0**	*0*
369	TOTAL ACCOUNT 449		0	**0**	*0*
370					
371	451 / MISCELLANEOUS SERVICE REVENUES	DA451	3,532,832	**77,330**	*3,455,502*
372					
373	454 / RENTS FROM ELECTRIC PROPERTY				
374	SUBSTATION EQUIPMENT	L 136	9,968,654	**432,926**	*9,535,728*
375	TRANSFORMER RENTALS	D11	17,330	**751**	*16,579*
376	LINE RENTALS	D11	2,067,177	**89,581**	*1,977,595*
377	COGENERATION	L 493	857,342	**39,671**	*817,672*
378	REAL ESTATE RENTS	L 202	240,575	**11,541**	*229,034*
379	DARK FIBER PROJECT	CIDA	448,000	**0**	*448,000*
380	POLE ATTACHMENTS	L 174	1,660,518	**122,453**	*1,538,065*
381	FACILITIES CHARGES	DA454	6,312,816	**358,513**	*5,954,303*
382	OTHER RENTALS	L 117	338,693	**14,677**	*324,016*
383	MISCELLANEOUS	DA454MISC	0	**0**	*0*
384	TOTAL ACCOUNT 454		21,911,105	**1,070,112**	*20,840,993*
385					
386	456 / OTHER ELECTRIC REVENUES				
387	TRANSMISSION NETWORK SERVICES- FIRM DA	D11	4,794,188	**207,757**	*4,586,431*
388	TRANSMISSION NETWORK SERVICES - DIST FACILITIE	D60	685,063	**28,084**	*656,979*
389	TRANSMISSION POINT-TO-POINT	D11	12,457,650	**539,855**	*11,917,795*
390	PHOTOVOLTAIC STATION SERVICE	L 188+CIAC	5,007	**278**	*4,729*
391	ENERGY EFFICIENCY RIDER	CIDA	0	**0**	*0*
392	STAND-BY SERVICE	DASTNBY	309,185	**0**	*309,185*
393	SIERRA PACIFIC USAGE CHARGE	E10	(0)	**(0)**	*(0)*
394	ANTELOPE	L 512	73,824	**3,207**	*70,617*
395	MISCELLANEOUS	L 202	1,769	**85**	*1,684*
396	TOTAL ACCOUNT 456		18,326,686	**779,265**	*17,547,421*
397					
398	TOTAL OTHER OPERATING REVENUES		44,555,238	**1,958,872**	*42,596,366*
399					
400	TOTAL OPERATING REVENUES		1,003,453,175	**46,776,951**	*956,676,224*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
401	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
402	STEAM POWER GENERATION				
403	OPERATION				
404	500 / SUPERVISION & ENGINEERING	D10	2,188,853	**94,854**	*2,093,999*
405	501 / FUEL	E10	149,354,701	**6,910,867**	*142,443,834*
406	502 / STEAM EXPENSES				
407	LABOR	D10	2,630,419	**113,990**	*2,516,429*
408	OTHER	E10	5,987,144	**277,034**	*5,710,110*
409	TOTAL ACCOUNT 502		8,617,563	**391,024**	*8,226,539*
410	505 / ELECTRIC EXPENSES				
411	LABOR	D10	1,173,413	**50,850**	*1,122,563*
412	OTHER	E10	1,340,126	**62,010**	*1,278,116*
413	TOTAL ACCOUNT 505		2,513,539	**112,860**	*2,400,679*
414	506 / MISCELLANEOUS EXPENSES	D10	11,439,644	**495,739**	*10,943,905*
415	507 / RENTS	L 116	269,318	**11,671**	*257,647*
416	STEAM OPERATION EXPENSES		174,383,618	**8,017,015**	*166,366,603*
417					
418	MAINTENANCE				
419	510 / SUPERVISION & ENGINEERING	D10	2,692,729	**116,690**	*2,576,039*
420	511 / STRUCTURES	D10	363,343	**15,746**	*347,597*
421	512 / BOILER PLANT				
422	LABOR	D10	6,236,518	**270,261**	*5,966,257*
423	OTHER	E10	12,634,271	**584,607**	*12,049,664*
424	TOTAL ACCOUNT 512		18,870,789	**854,867**	*18,015,922*
425	513 / ELECTRIC PLANT				
426	LABOR	D10	1,993,219	**86,377**	*1,906,842*
427	OTHER	E10	2,605,076	**120,541**	*2,484,535*
428	TOTAL ACCOUNT 513		4,598,295	**206,917**	*4,391,378*
429	514 / MISCELLANEOUS STEAM PLANT	D10	4,407,711	**191,009**	*4,216,702*
430	STEAM MAINTENANCE EXPENSES		30,932,867	**1,385,229**	*29,547,638*
431	TOTAL STEAM GENERATION EXPENSES		205,316,485	**9,402,244**	*195,914,241*
432					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
433	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
434	HYDRAULIC POWER GENERATION				
435	OPERATION				
436	535 / SUPERVISION & ENGINEERING	L 873	5,716,476	**248,861**	*5,467,615*
437	536 / WATER FOR POWER	D10	7,588,140	**328,833**	*7,259,307*
438	537 / HYDRAULIC EXPENSES	D10	11,953,308	**517,999**	*11,435,309*
439	538 / ELECTRIC EXPENSES				
440	LABOR	D10	1,178,782	**51,083**	*1,127,699*
441	OTHER	E10	487,345	**22,550**	*464,795*
442	TOTAL ACCOUNT 538		1,666,127	**73,633**	*1,592,494*
443	539 / MISCELLANEOUS EXPENSES	D10	3,071,458	**133,102**	*2,938,356*
444	540 / RENTS	D10	419,836	**18,194**	*401,642*
445	HYDRAULIC OPERATION EXPENSES		30,415,345	**1,320,622**	*29,094,723*
446					
447	MAINTENANCE				
448	541 / SUPERVISION & ENGINEERING	L 884	2,102,821	**91,126**	*2,011,695*
449	542 / STRUCTURES	D10	1,224,425	**53,061**	*1,171,364*
450	543 / RESERVOIRS, DAMS & WATERWAYS	D10	1,440,450	**62,422**	*1,378,028*
451	544 / ELECTRIC PLANT				
452	LABOR	D10	2,067,853	**89,611**	*1,978,242*
453	OTHER	E10	1,300,091	**60,157**	*1,239,934*
454	TOTAL ACCOUNT 544		3,367,944	**149,768**	*3,218,176*
455	545 / MISCELLANEOUS HYDRAULIC PLANT	L 117	3,212,310	**139,206**	*3,073,104*
456	HYDRAULIC MAINTENANCE EXPENSES		11,347,950	**495,583**	*10,852,367*
457	TOTAL HYDRAULIC GENERATION EXPENSES		41,763,295	**1,816,205**	*39,947,090*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
458	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
459	OTHER POWER GENERATION				
460	OPERATION				
461	546 / SUPERVISION & ENGINEERING	L 897	351,550	**15,234**	*336,316*
462	547 / FUEL				
463	DIESEL FUEL	E10	14,672	**679**	*13,993*
464	OTHER	E10	4,958,565	**229,440**	*4,729,125*
465	TOTAL ACCOUNT 547		4,973,237	**230,119**	*4,743,118*
466	548 / GENERATING EXPENSES				
467	LABOR	D10	12,967	**562**	*12,405*
468	OTHER	E10	464,632	**21,499**	*443,133*
469	TOTAL ACCOUNT 548		477,599	**22,061**	*455,538*
470	549 / MISCELLANEOUS EXPENSES	D10	478,875	**20,752**	*458,123*
471	550 / RENTS	D10	0	**0**	*0*
472	OTHER POWER OPER EXPENSES		6,281,261	**288,167**	*5,993,094*
473					
474	MAINTENANCE				
475	551 / SUPERVISION & ENGINEERING	L 907	44	**2**	*42*
476	552 / STRUCTURES	D10	193,536	**8,387**	*185,149*
477	553 / GENERATING & ELECTRIC PLANT				
478	LABOR	D10	3,509	**152**	*3,357*
479	OTHER	E10	122,742	**5,679**	*117,063*
480	TOTAL ACCOUNT 553		126,251	**5,832**	*120,419*
481	554 / MISCELLANEOUS EXPENSES	L 118	2,385,754	**103,387**	*2,282,367*
482	OTHER POWER MAINT EXPENSES		2,705,585	**117,607**	*2,587,978*
483	TOTAL OTHER POWER GENERATION EXP		8,986,846	**405,774**	*8,581,072*
484					
485	OTHER POWER SUPPLY EXPENSE				
486	555.0 / PURCHASED POWER				
487	POWER EXPENSE	E10	70,960,713	**3,283,459**	*67,677,254*
488	TRANSMISSION LOSSES	E10	1,366,000	**63,207**	*1,302,793*
489	TOTAL 555.0/PURCHASED POWER		72,326,713	**3,346,666**	*68,980,047*
490	555.1 / COGENERATION & SMALL POWER PROD				
491	CAPACITY RELATED	D10	0	**0**	*0*
492	ENERGY RELATED	E10	129,051,222	**5,971,394**	*123,079,828*
493	TOTAL 555.1/CSPP		129,051,222	**5,971,394**	*123,079,828*
494	555/TOTAL		201,377,935	**9,318,060**	*192,059,875*
495	556 / LOAD CONTROL & DISPATCHING EXPENSES	D10	165	**7**	*158*
496	557 / OTHER EXPENSES				
497	PCA/ EPC ACCOUNTS	D10	0	**0**	*0*
498	OTHER	D10	2,738,461	**118,672**	*2,619,789*
499	557/TOTAL		2,738,461	**118,672**	*2,619,789*
500	TOTAL OTHER POWER SUPPLY EXPENSES		204,116,561	**9,436,739**	*194,679,822*
501					
502	TOTAL PRODUCTION EXPENSES		460,183,187	**21,060,961**	*439,122,226*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
503	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
504	TRANSMISSION EXPENSES				
505	OPERATION				
506	560 / SUPERVISION & ENGINEERING	L 158	3,171,937	**137,792**	*3,034,145*
507	561 / LOAD DISPATCHING	D12	3,162,144	**137,032**	*3,025,112*
508	562 / STATION EXPENSES	L 136	2,113,074	**91,768**	*2,021,306*
509	563 / OVERHEAD LINE EXPENSES	L 141+146+151	3,059,773	**133,012**	*2,926,761*
510	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	E10	7,978,600	**369,182**	*7,609,418*
511	566 / MISCELLANEOUS EXPENSES	L 158	349,219	**15,170**	*334,049*
512	567 / RENTS	L 158	2,182,089	**94,792**	*2,087,297*
513	TOTAL TRANSMISSION OPERATION		22,016,837	**978,749**	*21,038,088*
514					
515	MAINTENANCE				
516	568 / SUPERVISION & ENGINEERING	L 158	563,653	**24,486**	*539,167*
517	569 / STRUCTURES	L 131	446,720	**19,364**	*427,356*
518	570 / STATION EQUIPMENT	L 136	3,644,442	**158,273**	*3,486,169*
519	571 / OVERHEAD LINES	L 141+146+151	2,908,685	**126,444**	*2,782,241*
520	573 / MISCELLANEOUS PLANT	L 158	(42)	**(2)**	*(40)*
521	TOTAL TRANSMISSION MAINTENANCE		7,563,458	**328,565**	*7,234,893*
522					
523	TOTAL TRANSMISSION EXPENSES		29,580,295	**1,307,314**	*28,272,981*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
524	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
525	DISTRIBUTION EXPENSES				
526	OPERATION				
527	580 / SUPERVISION & ENGINEERING	L 188	3,956,164	**224,096**	*3,732,068*
528	581 / LOAD DISPATCHING	D60	3,659,095	**150,003**	*3,509,092*
529	582 / STATION EXPENSES	L 172	1,355,913	**40,606**	*1,315,307*
530	583 / OVERHEAD LINE EXPENSES	L 174+175	3,234,009	**223,115**	*3,010,894*
531	584 / UNDERGROUND LINE EXPENSES	L 176+177	1,878,785	**30,359**	*1,848,426*
532	585 / STREET LIGHTING & SIGNAL SYSTEMS	L 186	84,813	**4,196**	*80,617*
533	586 / METER EXPENSES	L 180:183	4,244,729	**114,519**	*4,130,210*
534	587 / CUSTOMER INSTALLATIONS EXPENSE	L 185	1,616,481	**138,078**	*1,478,403*
535	588 / MISCELLANEOUS EXPENSES	L 188	5,301,340	**300,293**	*5,001,047*
536	589 / RENTS	L 188	591,115	**33,484**	*557,631*
537	TOTAL DISTRIBUTION OPERATION		25,922,444	**1,258,749**	*24,663,695*
538					
539	MAINTENANCE				
540	590 / SUPERVISION & ENGINEERING	L 188	397,289	**22,504**	*374,785*
541	591 / STRUCTURES	L 168	(11,761)	**(392)**	*(11,369)*
542	592 / STATION EQUIPMENT	L 172	3,993,039	**119,582**	*3,873,457*
543	593 / OVERHEAD LINES	L 174+175	14,982,202	**1,033,626**	*13,948,576*
544	594 / UNDERGROUND LINES	L 176+177	1,064,194	**17,196**	*1,046,998*
545	595 / LINE TRANSFORMERS	L 178	464,002	**42,084**	*421,918*
546	596 / STREET LIGHTING & SIGNAL SYSTEMS	L 186	621,299	**30,741**	*590,558*
547	597 / METERS	L 180:183	704,013	**18,994**	*685,019*
548	598 / MISCELLANEOUS PLANT	L 188	146,655	**8,307**	*138,348*
549	TOTAL DISTRIBUTION MAINTENANCE		22,360,932	**1,292,643**	*21,068,289*
550	TOTAL DISTRIBUTION EXPENSES		48,283,376	**2,551,393**	*45,731,983*
551					
552	CUSTOMER ACCOUNTING EXPENSES				
553	901 / SUPERVISION	L 977	439,550	**20,343**	*419,207*
554	902 / METER READING	CW902	2,193,502	**152,560**	*2,040,942*
555	903 / CUSTOMER RECORDS & COLLECTIONS	CW903	13,712,922	**513,166**	*13,199,756*
556	904 / UNCOLLECTIBLE ACCOUNTS	CW904	4,638,855	**158,891**	*4,479,964*
557	905 / MISC EXPENSES	L 554+555+556	354	**14**	*340*
558	TOTAL CUSTOMER ACCOUNTING EXPENSES		20,985,183	**844,974**	*20,140,209*
559					
560	CUSTOMER SERVICES & INFORMATION EXPENSES				
561	907 / SUPERVISION	L 985	376,192	**13,789**	*362,403*
562	908 / CUSTOMER ASSISTANCE				
563	SYSTEM CONSERVATION	E10	333,928	**15,451**	*318,477*
564	OTHER CUSTOMER ASSISTANCE	DA908	6,229,580	**225,125**	*6,004,455*
565	TOTAL ACCOUNT 908		6,563,508	**240,577**	*6,322,931*
566	909 / INFORMATION & INSTRUCTIONAL	DA909	32,557	**1,218**	*31,339*
567	910 / MISCELLANEOUS EXPENSES	L 562+566	913,998	**33,505**	*880,493*
568	TOTAL CUST SERV & INFORMATN EXPENSES		7,886,255	**289,088**	*7,597,167*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
569	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
570	ADMINISTRATIVE & GENERAL EXPENSES				
571	920 / ADMINISTRATIVE & GENERAL SALARIES	LABOR	57,264,382	**2,619,964**	*54,644,418*
572	921 / OFFICE SUPPLIES	LABOR	14,905,281	**681,948**	*14,223,333*
573	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-	LABOR	(28,798,299)	**(1,317,582)**	*(27,480,717)*
574	923 / OUTSIDE SERVICES	LABOR	7,441,043	**340,443**	*7,100,600*
575	924 / PROPERTY INSURANCE				
576	PRODUCTION - STEAM	D10	809,837	**35,094**	*774,743*
577	ALL RISK & MISCELLANEOUS	P110P	2,545,937	**109,115**	*2,436,822*
578	TOTAL ACCOUNT 924		3,355,774	**144,209**	*3,211,565*
579	925 / INJURIES & DAMAGES	LABOR	5,862,281	**268,212**	*5,594,069*
580	926 / EMPLOYEE PENSIONS & BENEFITS	LABOR	26,543,429	**1,214,417**	*25,329,012*
581	EMPLOYEE PENSIONS & BENEFITS - OREGON	CODA	893,024	**893,024**	*0*
582	EMPLOYEE PENSIONS & BENEFITS - IDAHO	CIDA	17,153,713	**0**	*17,153,713*
583	EMPLOYEE PENSIONS & BENEFITS - FERC	D11	190,950	**8,275**	*182,675*
584	927 / FRANCHISE REQUIREMENTS	CIDA	2,633	**0**	*2,633*
585	928 / REGULATORY COMMISSION EXPENSES				
586	928.101 / FERC ADMIN ASSESS & SECURITIES				
587	CAPACITY RELATED	D10	1,792,385	**77,673**	*1,714,712*
588	ENERGY RELATED	E10	762,063	**35,262**	*726,801*
589	928.101 / FERC ORDER 472	E99	503,013	**23,449**	*479,564*
590	928.101 / FERC MISCELLANIOUS	D11	581,969	**25,220**	*556,749*
591	928.102 FERC RATE CASE	D11	727	**32**	*695*
592	928.104 / FERC OREGON HYDRO	D11	163,733	**7,095**	*156,638*
593	928.202 / IDAHO PUC -RATE CASE	CIDA	55,373	**0**	*55,373*
594	928.203 / IDAHO PUC - OTHER	CIDA	67,748	**0**	*67,748*
595	928.301 / OREGON PUC - FILING FEES	CODA	0	**0**	*0*
596	928.302 / OREGON PUC - RATE CASE	CODA	6,748	**6,748**	*0*
597	928.303 / OREGON PUC - OTHER	CODA	299,262	**299,262**	*0*
598	IPC/PUC JSS TRUE-UP ADJ	PTD	0	**0**	*0*
599	TOTAL ACCOUNT 928		4,233,022	**474,741**	*3,758,281*
600	929 / DUPLICATE CHARGES	LABOR	0	**0**	*0*
601	930.1 / GENERAL ADVERTISING	LABOR	0	**0**	*0*
602	930.2 / MISCELLANEOUS EXPENSES	LABOR	3,790,748	**173,435**	*3,617,313*
603	931 / RENTS	L 202	25,188	**1,208**	*23,980*
604	TOTAL ADM & GEN OPERATION		112,863,170	**5,502,294**	*107,360,876*
605	PLUS:				
606	935 / GENERAL PLANT MAINTENANCE	L 202	4,370,619	**209,663**	*4,160,956*
607	416 / MERCHANDISING EXPENSE	D60	614,155	**25,177**	*588,978*
608	TOTAL OPER & MAINT EXPENSES		684,766,241	**31,790,864**	*652,975,377*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
609	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***				
610					
611	DEPRECIATION EXPENSE				
612	310-316 / STEAM PRODUCTION	L 116	19,091,068	**827,315**	*18,263,753*
613	330-336 / HYDRAULIC PRODUCTION	L 117	15,428,476	**668,596**	*14,759,881*
614	340-346 / OTHER PRODUCTION	L 118	5,444,322	**235,931**	*5,208,392*
615	TOTAL PRODUCTION PLANT		39,963,867	**1,731,842**	*38,232,025*
616					
617	TRANSMISSION PLANT				
618	350 / LAND & LAND RIGHTS	L 126	455,047	**19,730**	*435,318*
619	352 / STRUCTURES & IMPROVEMENTS	L 131	954,983	**41,395**	*913,588*
620	353 / STATION EQUIPMENT	L 136	7,369,784	**320,060**	*7,049,724*
621	354 / TOWERS & FIXTURES	L 141	2,940,288	**127,418**	*2,812,870*
622	355 / POLES & FIXTURES	L 146	2,899,667	**126,568**	*2,773,099*
623	356 / OVERHEAD CONDUCTORS & DEVICES	L 151	3,322,211	**144,455**	*3,177,757*
624	359 / ROADS & TRAILS	L 156	3,133	**136**	*2,997*
625	TOTAL TRANSMISSION PLANT		17,945,115	**779,761**	*17,165,353*
626					
627	DISTRIBUTION PLANT				
628	360 / LAND & LAND RIGHTS	L 164	0	**0**	*0*
629	361 / STRUCTURES & IMPROVEMENTS	L 168	593,228	**19,768**	*573,460*
630	362 / STATION EQUIPMENT	L 172	3,664,706	**109,749**	*3,554,957*
631	364 / POLES, TOWERS & FIXTURES	L 174	7,653,065	**564,366**	*7,088,699*
632	365 / OVERHEAD CONDUCTORS & DEVICES	L 175	3,677,442	**221,206**	*3,456,236*
633	366 / UNDERGROUND CONDUIT	L 176	982,581	**13,753**	*968,828*
634	367 / UNDERGROUND CONDUCTORS & DEVICES	L 177	3,909,247	**65,303**	*3,843,944*
635	368 / LINE TRANSFORMERS	L 178	7,106,085	**644,511**	*6,461,574*
636	369 / SERVICES	L 179	1,829,475	**93,896**	*1,735,579*
637	370 / ALL OTHER METERS	L 180	1,024,935	**72,389**	*952,545*
638	AMI	L 181	3,677,845	**130,747**	*3,547,097*
639	PRE-AMI (OREGON)	L 182	0	**0**	*0*
640	PRE-AMI (IDAHO)	L 183	10,551,354	**0**	*10,551,354*
641	371 / INSTALLATIONS ON CUSTOMER PREMISES	L 185	29,256	**2,499**	*26,757*
642	373 / STREET LIGHTING SYSTEMS	L 186	179,433	**8,878**	*170,555*
643	TOTAL DISTRIBUTION PLANT		44,878,651	**1,947,066**	*42,931,585*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
644	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***				
645					
646	GENERAL PLANT				
647	389 / LAND & LAND RIGHTS	L 191	0	**0**	*0*
648	390 / STRUCTURES & IMPROVEMENTS	L 192	1,954,946	**93,781**	*1,861,165*
649	391 / OFFICE FURNITURE & EQUIPMENT	L 193	7,851,477	**376,643**	*7,474,834*
650	392 / TRANSPORTATION EQUIPMENT	L 194	222,415	**10,669**	*211,745*
651	393 / STORES EQUIPMENT	L 195	85,304	**4,092**	*81,212*
652	394 / TOOLS, SHOP & GARAGE EQUIPMENT	L 196	283,465	**13,598**	*269,867*
653	395 / LABORATORY EQUIPMENT	L 197	684,508	**32,836**	*651,671*
654	396 / POWER OPERATED EQUIPMENT	L 198	0	**0**	*0*
655	397 / COMMUNICATIONS EQUIPMENT	L 199	2,035,419	**97,641**	*1,937,778*
656	398 / MISCELLANEOUS EQUIPMENT	L 200	505,034	**24,227**	*480,807*
657	TOTAL GENERAL PLANT		13,622,568	**653,488**	*12,969,080*
658					
659	TOTAL DEPRECIATION EXPENSE		116,410,200	**5,112,157**	*111,298,044*
660					
661	DEPRECIATION ON DISALLOWED COSTS	L 113	(296,299)	**(13,624)**	*(282,675)*
662	TOTAL DEPRECIATION EXPENSE		116,113,901	**5,098,532**	*111,015,369*
663					
664	AMORTIZATION EXPENSE				
665	INTANGIBLE PLANT	L 113	7,231,531	**332,515**	*6,899,015*
666	HYDRAULIC PRODUCTION	L 117	0	**0**	*0*
667	ADJUSTMENTS, GAINS & LOSSES	L 113	(22,723)	**(1,045)**	*(21,678)*
668	TOTAL AMORTIZATION EXPENSE		7,208,808	**331,470**	*6,877,337*
669					
670	TOTAL DEPRECIATION & AM0RTIZATION EXP		123,322,709	**5,430,003**	*117,892,706*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
671	***TABLE 7-TAXES OTHER THAN INCOME TAXES***				
672					
673	TAXES OTHER THAN INCOME				
674	FEDERAL TAXES				
675	FICA	LABOR	0	**0**	*0*
676	FUTA	LABOR	0	**0**	*0*
677	LESS PAYROLL DEDUCTION	LABOR	0	**0**	*0*
678					
679	STATE TAXES				
680	AD VALOREM TAXES				
681	JIM BRIDGER STATION	L 116	1,412,547	**61,213**	*1,351,334*
682	VALMY	L 116	1,281,838	**55,549**	*1,226,290*
683	BOARDMAN	L 116	308,283	**13,360**	*294,924*
684	OTHER-PRODUCTION PLANT	L 120	4,633,668	**200,801**	*4,432,868*
685	OTHER-TRANSMISSION PLANT	L 158	5,403,916	**234,752**	*5,169,164*
686	OTHER-DISTRIBUTION PLANT	L 188	8,528,002	**483,067**	*8,044,935*
687	OTHER-GENERAL PLANT	L 202	1,364,526	**65,458**	*1,299,068*
688	SUB-TOTAL		22,932,783	**1,114,199**	*21,818,584*
689					
690	LICENSES - HYDRO PROJECTS	L 117	4,830	**209**	*4,620*
691					
692	REGULATORY COMMISSION FEES				
693	STATE OF IDAHO	CIDA	1,837,184	**0**	*1,837,184*
694	STATE OF OREGON	CODA	140,942	**140,942**	*0*
695	STATE OF NEVADA	D11	0	**0**	*0*
696					
697	FRANCHISE TAXES				
698	STATE OF OREGON	CODA	680,159	**680,159**	*0*
699	STATE OF NEVADA	D11	0	**0**	*0*
700					
701	OTHER STATE TAXES				
702	UNEMPLOYMENT TAXES	LABOR	0	**0**	*0*
703	HYDRO GENERATION KWH TAX	E10	1,732,697	**80,174**	*1,652,523*
704	IRRIGATION-PIC	E10	303,932	**14,063**	*289,869*
705					
706	TOTAL TAXES OTHER THAN INCOME		27,632,526	**2,029,747**	*25,602,779*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
707	***TABLE 8-REGULATORY DEBITS & CREDITS***				
708	REGULATORY DEBITS/CREDITS				
709	STATE OF IDAHO	CIDA	0	**0**	*0*
710	STATE OF OREGON	CODA	27,757	**27,757**	*0*
711					
712	TOTAL REGULATORY DEBITS/CREDITS		27,757	**27,757**	*0*
713					
714					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
715	***TABLE 9-INCOME TAXES***				
716					
717	410/411 NET PROVISION FOR DEFERRED INCOME TAXES				
718	ACCOUNT #282 - RELATED	P101P	45,323,566	**2,174,216**	*43,149,350*
719	ACCOUNTS #190 & #283 - RELATED	L 746	(5,747,109)	**(256,972)**	*(5,490,137)*
720	TOTAL NET PROVISION FOR DEFERRED INCOME TAXES		39,576,457	**1,917,244**	*37,659,213*
721					
722	411.4 - INVESTMENT TAX CREDIT ADJUSTMENT	P101P	(470,989)	**(22,594)**	*(448,395)*
723					
724	SUMMARY OF INCOME TAXES				
725					
726	TOTAL FEDERAL INCOME TAX		(6,924,112)	**(549,346)**	*(6,374,766)*
727					
728	STATE INCOME TAX				
729	STATE OF IDAHO		2,346,112	**72,380**	*2,273,732*
730	STATE OF OREGON		(68,768)	**(5,341)**	*(63,427)*
731	OTHER STATES		(7,313)	**(1,032)**	*(6,282)*
732	TOTAL STATE INCOME TAXES		2,270,031	**66,007**	*2,204,023*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
733	***TABLE 10-CALCULATION OF FEDERAL INCOME TAX***				
734	OPERATING REVENUES		1,003,453,175	**46,776,951**	*956,676,224*
735					
736	OPERATING EXPENSES				
737	OPERATION & MAINTENANCE		684,766,241	**31,790,864**	*652,975,377*
738	DEPRECIATION EXPENSE		116,113,901	**5,098,532**	*111,015,369*
739	AMORTIZATION OF LIMITED TERM PLANT		7,208,808	**331,470**	*6,877,337*
740	TAXES OTHER THAN INCOME		27,632,526	**2,029,747**	*25,602,779*
741	REGULATORY DEBITS/CREDITS		27,757	**27,757**	*0*
742	TOTAL OPERATING EXPENSES		835,749,232	**39,278,370**	*796,470,862*
743					
744	BOOK-TAX ADJUSTMENT	L 742	0	**0**	*0*
745					
746	INCOME BEFORE TAX ADJUSTMENTS		167,703,943	**7,498,580**	*160,205,362*
747					
748	INCOME STATEMENT ADJUSTMENTS				
749	INTEREST EXPENSE SYNCHRONIZATION	L 353	84,514,916	**4,120,543**	*80,394,373*
750					
751	NET OPERATING INCOME BEFORE TAXES		83,189,027	**3,378,037**	*79,810,990*
752					
753	ALLOWANCE FOR AFUDC	P101P	0	**0**	*0*
754	FEDERAL INCOME TAX ADJUSTMENTS - PLANT	P101P	(116,297,982)	**(5,578,928)**	*(110,719,054)*
755	FEDERAL INCOME TAX ADJUSTMENTS - OTHER	L 746	15,595,809	**697,339**	*14,898,470*
756					
757	NET OPER INCOME BEFORE STATE INCOME TAXES		(17,513,146)	**(1,503,552)**	*(16,009,594)*
758					
759	TOTAL STATE INCOME TAXES (ALLOWED)	L 789+790+812+813+825+	2,270,031	**66,007**	*2,204,023*
760					
761	TOTAL FEDERAL TAXABLE INCOME		(19,783,177)	**(1,569,560)**	*(18,213,617)*
762					
763	FEDERAL TAX AT 35 PERCENT: ORDERED EFF. RATE	@ **35.00%**	(6,924,112)	**(549,346)**	*(6,374,766)*
764	ADD : TAX DEFICIENCY PAYMENT	L 763	0	**0**	*0*
765	PRIOR YEARS' TAX ADJUSTMENT	L 763	0	**0**	*0*
766					
767	TOTAL FEDERAL INCOME TAX		(6,924,112)	**(549,346)**	*(6,374,766)*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
768	***TABLE 11-OREGON STATE INCOME TAX***				
769					
770	NET OPERATING INCOME BEFORE TAXES - OREGON	L 751	83,189,027	**3,378,037**	*79,810,990*
771					
772	ALLOWANCE FOR AFUDC	P101P	0	**0**	*0*
773	STATE INCOME TAX ADJUSTMENTS - PLANT	P101P	(116,297,982)	**(5,578,928)**	*(110,719,054)*
774	STATE INCOME TAX ADJUSTMENTS - OTHER	L 746	15,595,809	**697,339**	*14,898,470*
775	ADD: MFG DEDUCTION NOT ALLOWED	L 746	0	**0**	*0*
776					
777	TOTAL STATE INCOME TAX ADJUSTMENTS - OREGON		(100,702,173)	**(4,881,590)**	*(95,820,583)*
778					
779	INCOME SUBJECT TO OREGON TAX		(17,513,146)	**(1,503,552)**	*(16,009,594)*
780					
781	IERCO TAXABLE INCOME	E10	10,200,000	**471,969**	*9,728,031*
782	BONUS DEPRECIATION & OTHER OREGON ADJ	P101P	(15,609,404)	**(748,798)**	*(14,860,606)*
783					
784	TOTAL STATE TAXABLE INCOME - OREGON		(22,922,550)	**(1,780,381)**	*(21,142,169)*
785					
786	OREGON TAX AT 0.3 PERCENT: ORDERED EFF. RATE	@ **0.30%**	(68,768)	**(5,341)**	*(63,427)*
787	LESS: INVESTMENT TAX CREDIT	P101P	0	**0**	*0*
788					
789	STATE INCOME TAX ALLOWED - OREGON		(68,768)	**(5,341)**	*(63,427)*
790	ADD : TAX DEFICIENCY PAYMENT	L 786	0	**0**	*0*
791	PRIOR YEARS' TAX ADJUSTMENT	L 786	0	**0**	*0*
792					
793	STATE INCOME TAX PAID - OREGON		(68,768)	**(5,341)**	*(63,427)*
794					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
795	***TABLE 12-IDAHO STATE INCOME TAX***				
796					
797	NET OPERATING INCOME BEFORE TAXES - IDAHO	L 751	83,189,027	**3,378,037**	*79,810,990*
798					
799	ALLOWANCE FOR AFUDC	P101P	0	**0**	*0*
800	STATE INCOME TAX ADJUSTMENTS - PLANT	P101P	(116,297,982)	**(5,578,928)**	*(110,719,054)*
801	STATE INCOME TAX ADJUSTMENTS - OTHER	L 746	15,595,809	**697,339**	*14,898,470*
802					
803	INCOME SUBJECT TO IDAHO TAX		(17,513,146)	**(1,503,552)**	*(16,009,594)*
804					
805	IERCO TAXABLE INCOME	E10	10,200,000	**471,969**	*9,728,031*
806	BONUS DEPRECIATION ADJUSTMENT	P101P	96,577,023	**4,632,894**	*91,944,129*
807	TOTAL STATE TAXABLE INCOME - IDAHO		89,263,877	**3,601,312**	*85,662,566*
808					
809	IDAHO TAX AT 5.9 PERCENT: ORDERED EFF. RATE	@ **5.90%**	5,266,569	**212,477**	*5,054,091*
810	LESS: INVESTMENT TAX CREDIT	P101P	2,920,457	**140,097**	*2,780,360*
811					
812	STATE INCOME TAX ALLOWED - IDAHO		2,346,112	**72,380**	*2,273,732*
813	ADD : TAX DEFICIENCY PAYMENT	L 809	0	**0**	*0*
814	PRIOR YEARS' TAX ADJUSTMENT	L 809	0	**0**	*0*
815	STATE INCOME TAX PAID - IDAHO		2,346,112	**72,380**	*2,273,732*
816					
817					
818	OTHER STATE INCOME TAX				
819	INCOME SUBJECT TO TAX		(17,513,146)	**(1,503,552)**	*(16,009,594)*
820					
821	IERCO TAXABLE INCOME	E10	10,200,000	**471,969**	*9,728,031*
822	BONUS DEPRECIATION ADJUSTMENT	P101P	0	**0**	*0*
823	TOTAL TAXABLE INCOME-OTHER STATES		(7,313,146)	**(1,031,583)**	*(6,281,563)*
824					
825	OTHER TAX AT 0.1 PERCENT		(7,313)	**(1,032)**	*(6,282)*
826	ADD : TAX DEFICIENCY PAYMENT	L 815	0	**0**	*0*
827	PRIOR YEARS' TAX ADJUSTMENT	L 815	0	**0**	*0*
828	OTHER STATES' INCOME TAX PAID		(7,313)	**(1,032)**	*(6,282)*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
829	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
830	STEAM POWER GENERATION				
831	OPERATION				
832	500 / SUPERVISION & ENGINEERING	L 833-843	251,120	**10,882**	*240,238*
833	501 / FUEL	D10	0	**0**	*0*
834	502 / STEAM EXPENSES				
835	LABOR	D10	0	**0**	*0*
836	OTHER	D10	0	**0**	*0*
837	TOTAL ACCOUNT 502		0	**0**	*0*
838	505 / ELECTRIC EXPENSES				
839	LABOR	D10	0	**0**	*0*
840	OTHER	D10	0	**0**	*0*
841	TOTAL ACCOUNT 505		0	**0**	*0*
842	506 / MISCELLANEOUS EXPENSES	D10	25,816	**1,119**	*24,697*
843	507 / RENTS	D10	0	**0**	*0*
844	STEAM OPERATION EXPENSES		276,936	**12,001**	*264,935*
845					
846	MAINTENANCE				
847	510 / SUPERVISION & ENGINEERING	L 848-857	0	**0**	*0*
848	511 / STRUCTURES	D10	0	**0**	*0*
849	512 / BOILER PLANT				
850	LABOR	D10	0	**0**	*0*
851	OTHER	D10	0	**0**	*0*
852	TOTAL ACCOUNT 512		0	**0**	*0*
853	513 / ELECTRIC PLANT				
854	LABOR	D10	0	**0**	*0*
855	OTHER	D10	0	**0**	*0*
856	TOTAL ACCOUNT 513		0	**0**	*0*
857	514 / MISCELLANEOUS STEAM PLANT	D10	0	**0**	*0*
858	STEAM MAINTENANCE EXPENSES		0	**0**	*0*
859	TOTAL STEAM GENERATION EXPENSES		276,936	**12,001**	*264,935*
860					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
861	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
862	HYDRAULIC POWER GENERATION				
863	OPERATION				
864	535 / SUPERVISION & ENGINEERING	L 865-872	4,138,379	**180,160**	*3,958,219*
865	536 / WATER FOR POWER	E10	557,584	**25,800**	*531,784*
866	537 / HYDRAULIC EXPENSES	D10	4,669,049	**202,334**	*4,466,715*
867	538 / ELECTRIC EXPENSES				
868	LABOR	D10	1,133,916	**49,138**	*1,084,778*
869	OTHER	D10	0	**0**	*0*
870	TOTAL ACCOUNT 538		1,133,916	**49,138**	*1,084,778*
871	539 / MISCELLANEOUS EXPENSES	D10	1,878,098	**81,388**	*1,796,710*
872	540 / RENTS	D10	0	**0**	*0*
873	HYDRAULIC OPERATION EXPENSES		12,377,026	**538,820**	*11,838,206*
874					
875	MAINTENANCE				
876	541 / SUPERVISION & ENGINEERING	L 877-883	1,632,395	**70,740**	*1,561,655*
877	542 / STRUCTURES	D10	715,498	**31,006**	*684,492*
878	543 / RESERVOIRS, DAMS & WATERWAYS	D10	632,240	**27,398**	*604,842*
879	544 / ELECTRIC PLANT				
880	LABOR	D10	1,989,149	**86,200**	*1,902,949*
881	OTHER	D10	0	**0**	*0*
882	TOTAL ACCOUNT 544		1,989,149	**86,200**	*1,902,949*
883	545 / MISCELLANEOUS HYDRAULIC PLANT	D10	1,934,114	**83,815**	*1,850,299*
884	HYDRAULIC MAINTENANCE EXPENSES		6,903,396	**299,160**	*6,604,236*
885	TOTAL HYDRAULIC GENERATION EXPENSES		19,280,422	**837,980**	*18,442,442*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
886	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
887	OTHER POWER GENERATION				
888	OPERATION				
889	546 / SUPERVISION & ENGINEERING	L 890-896	286,810	**12,429**	*274,381*
890	547 / FUEL	E10	0	**0**	*0*
891	548 / GENERATING EXPENSES				
892	LABOR	D10	327,712	**14,201**	*313,511*
893	OTHER	D10	0	**0**	*0*
894	TOTAL ACCOUNT 548		327,712	**14,201**	*313,511*
895	549 / MISCELLANEOUS EXPENSES	D10	323,105	**14,002**	*309,103*
896	550 / RENTS	D10	0	**0**	*0*
897	OTHER POWER OPER EXPENSES		937,627	**40,632**	*896,995*
898					
899	MAINTENANCE				
900	551 / SUPERVISION & ENGINEERING	L 901-906	0	**0**	*0*
901	552 / STRUCTURES	D10	127,875	**5,541**	*122,334*
902	553 / GENERATING & ELECTRIC PLANT				
903	LABOR	D10	88,691	**3,843**	*84,848*
904	OTHER	D10	0	**0**	*0*
905	TOTAL ACCOUNT 553		88,691	**3,843**	*84,848*
906	554 / MISCELLANEOUS EXPENSES	D10	355,196	**15,392**	*339,804*
907	OTHER POWER MAINT EXPENSES		571,762	**24,777**	*546,985*
908	TOTAL OTHER POWER GENERATION EXP		1,509,389	**65,410**	*1,443,979*
909					
910	OTHER POWER SUPPLY EXPENSE				
911	555.0 / PURCHASED POWER	E10	0	**0**	*0*
912	555.1 / COGENERATION & SMALL POWER PROD				
913	CAPACITY RELATED	D10	0	**0**	*0*
914	ENERGY RELATED	E10	0	**0**	*0*
915	TOTAL 555.1/CSPP		0	**0**	*0*
916	555/TOTAL		0	**0**	*0*
917	556 / LOAD CONTROL & DISPATCHING EXPENSES	D10	0	**0**	*0*
918	557 / OTHER EXPENSES	D10	1,969,127	**85,332**	*1,883,795*
919	TOTAL OTHER POWER SUPPLY EXPENSES		1,969,127	**85,332**	*1,883,795*
920					
921	TOTAL PRODUCTION EXPENSES		23,035,874	**1,000,724**	*22,035,150*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
922	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
923	TRANSMISSION EXPENSES				
924	OPERATION				
925	560 / SUPERVISION & ENGINEERING	L 158	1,876,009	**81,496**	*1,794,513*
926	561 / LOAD DISPATCHING	D12	2,606,404	**112,949**	*2,493,455*
927	562 / STATION EXPENSES	L 136	1,406,018	**61,062**	*1,344,956*
928	563 / OVERHEAD LINE EXPENSES	L 141+146+151	325,684	**14,158**	*311,526*
929	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	E10	0	**0**	*0*
930	566 / MISCELLANEOUS EXPENSES	L 523	29,797	**1,317**	*28,480*
931	567 / RENTS	L 158	0	**0**	*0*
932	TOTAL TRANSMISSION OPERATION		6,243,912	**270,981**	*5,972,931*
933					
934	MAINTENANCE				
935	568 / SUPERVISION & ENGINEERING	L 158	128,017	**5,561**	*122,456*
936	569 / STRUCTURES	L 131	318,561	**13,808**	*304,753*
937	570 / STATION EQUIPMENT	L 136	1,938,436	**84,184**	*1,854,252*
938	571 / OVERHEAD LINES	L 141+146+151	835,101	**36,303**	*798,798*
939	573 / MISCELLANEOUS PLANT	L 158	0	**0**	*0*
940	TOTAL TRANSMISSION MAINTENANCE		3,220,115	**139,856**	*3,080,259*
941					
942	TOTAL TRANSMISSION EXPENSES		9,464,027	**410,837**	*9,053,190*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
943	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
944	DISTRIBUTION EXPENSES				
945	OPERATION				
946	580 / SUPERVISION & ENGINEERING	L 188	2,826,824	**160,125**	*2,666,699*
947	581 / LOAD DISPATCHING	D60	2,940,004	**120,524**	*2,819,480*
948	582 / STATION EXPENSES	L 172	841,162	**25,191**	*815,971*
949	583 / OVERHEAD LINE EXPENSES	L 174+175	2,454,103	**169,309**	*2,284,794*
950	584 / UNDERGROUND LINE EXPENSES	L 176+177	640,628	**10,352**	*630,276*
951	585 / STREET LIGHTING & SIGNAL SYSTEMS	L 186	63,072	**3,121**	*59,951*
952	586 / METER EXPENSES	L 180:183	3,037,247	**81,942**	*2,955,305*
953	587 / CUSTOMER INSTALLATIONS EXPENSE	L 185	1,047,805	**89,502**	*958,303*
954	588 / MISCELLANEOUS EXPENSES	L 550	3,092,742	**163,427**	*2,929,315*
955	589 / RENTS	L 188	107	**6**	*101*
956	TOTAL DISTRIBUTION OPERATION		16,943,694	**823,498**	*16,120,196*
957					
958	MAINTENANCE				
959	590 / SUPERVISION & ENGINEERING	L 188	303,700	**17,203**	*286,497*
960	591 / STRUCTURES	L 168	0	**0**	*0*
961	592 / STATION EQUIPMENT	L 172	2,190,252	**65,593**	*2,124,659*
962	593 / OVERHEAD LINES	L 174+175	5,129,594	**353,892**	*4,775,702*
963	594 / UNDERGROUND LINES	L 176+177	645,314	**10,428**	*634,886*
964	595 / LINE TRANSFORMERS	L 178	24,820	**2,251**	*22,569*
965	596 / STREET LIGHTING & SIGNAL SYSTEMS	L 186	327,168	**16,188**	*310,980*
966	597 / METERS	L 180:183	511,932	**13,811**	*498,121*
967	598 / MISCELLANEOUS PLANT	L 188	107,136	**6,069**	*101,067*
968	TOTAL DISTRIBUTION MAINTENANCE		9,239,916	**485,435**	*8,754,481*
969	TOTAL DISTRIBUTION EXPENSES		26,183,610	**1,308,933**	*24,874,677*
970					
971	CUSTOMER ACCOUNTING EXPENSES				
972	901 / SUPERVISION	L 973	359,608	**25,011**	*334,597*
973	902 / METER READING	CW902	2,269,828	**157,869**	*2,111,959*
974	903 / CUSTOMER RECORDS & COLLECTIONS	CW903	6,906,743	**258,465**	*6,648,278*
975	904 / UNCOLLECTIBLE ACCOUNTS	CW904	0	**0**	*0*
976	905 / MISC EXPENSES	L 973-975	0	**0**	*0*
977	TOTAL CUSTOMER ACCOUNTING EXPENSES		9,536,179	**441,344**	*9,094,835*
978					
979	CUSTOMER SERVICES & INFORMATION EXPENSES				
980	907 / SUPERVISION	L 984	279,335	**10,239**	*269,096*
981	908 / CUSTOMER ASSISTANCE	L 562	3,632,577	**133,147**	*3,499,430*
982	908 / ENERGY EFFICIENCY RIDER	CIDA	0	**0**	*0*
983	909 / INFORMATION & INSTRUCTIONAL	L 566	0	**0**	*0*
984	910 / MISCELLANEOUS EXPENSES	L 981+983	508,430	**18,636**	*489,794*
985	TOTAL CUST SERV & INFORMATN EXPENSES		4,420,342	**162,022**	*4,258,320*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION		ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
986	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***					
987	ADMINISTRATIVE & GENERAL EXPENSES					
988	920 / ADMINISTRATIVE & GENERAL SALARIES		PTDCAS	40,893,203	**1,871,190**	*39,022,013*
989	921 / OFFICE SUPPLIES		PTDCAS	194,129	**8,883**	*185,246*
990	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-		SUBEX	0	**0**	*0*
991	923 / OUTSIDE SERVICES		PTDCAS	0	**0**	*0*
992	924 / PROPERTY INSURANCE					
993	PRODUCTION - STEAM	L	116	0	**0**	*0*
994	ALL RISK & MISCELLANEOUS		P110P	231,444	**9,919**	*221,525*
995	TOTAL ACCOUNT 924			231,444	**9,919**	*221,525*
996	925 / INJURIES & DAMAGES		LABOR	162,751	**7,446**	*155,305*
997	926 / EMPLOYEE PENSIONS & BENEFITS		LABOR	0	**0**	*0*
998	927 / FRANCHISE REQUIREMENTS		CIDA	0	**0**	*0*
999	928 / REGULATORY COMMISSION EXPENSES					
1000	928.101 / FERC ADMIN ASSESS & SECURITIES					
1001	CAPACITY RELATED		D10	0	**0**	*0*
1002	ENERGY RELATED		E10	0	**0**	*0*
1003	928.101 / FERC ORDER 472		E99	0	**0**	*0*
1004	928.101 / FERC MISCELLANIOUS	L	RESREV	0	**0**	*0*
1005	928.102 FERC RATE CASE		RESREV	0	**0**	*0*
1006	928.104 / FERC OREGON HYDRO		RESREV	0	**0**	*0*
1007	SEC EXPENSES	L	204	0	**0**	*0*
1008	928.202 / IDAHO PUC -RATE CASE		CIDA	0	**0**	*0*
1009	928.203 / IDAHO PUC - OTHER		CIDA	0	**0**	*0*
1010	928.301 / OREGON PUC - FILING FEES		CODA	0	**0**	*0*
1011	928.302 / OREGON PUC - RATE CASE		CODA	0	**0**	*0*
1012	928.303 / OREGON PUC - OTHER		CODA	0	**0**	*0*
1013	IPC/PUC JSS TRUE-UP ADJ		PTD	0	**0**	*0*
1014	TOTAL ACCOUNT 928			0	**0**	*0*
1015	929 / DUPLICATE CHARGES		SUBEX	0	**0**	*0*
1016	930.1 / GENERAL ADVERTISING		RELAB	0	**0**	*0*
1017	930.2 / MISCELLANEOUS EXPENSES		PTDCAS	0	**0**	*0*
1018	931 / RENTS	L	202	132,751	**6,368**	*126,383*
1019	TOTAL ADM & GEN OPERATION			41,614,278	**1,903,806**	*39,710,472*
1020	PLUS:					
1021	935 / GENERAL PLANT MAINTENANCE		P3908	1,072,390	**51,444**	*1,020,946*
1022	416 / MERCHANDISING EXPENSE		E10	0	**0**	*0*
1023	TOTAL OPER & MAINT EXPENSES			115,326,700	**5,279,110**	*110,047,590*
1024	**TOTAL LABOR - RATIO (%)**			100.00%	**4.58%**	*95.42%*
1025						

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
1026	***TABLE 14-ALLOCATION FACTORS***				
1027					
1028	CAPACITY RELATED KW				
1029	PRODUCTION RELATED COINCIDENT PEAKS @ GEN	D10	2,401,942	**104,089**	*2,297,853*
1030	SYSTEM TRANSMISSION SERVICE @ GENERATION I	D11	2,401,942	**104,089**	*2,297,853*
1031	RETAIL TRANSMISSION SERVICE @ GENERATION LEVE	D12	2,401,942	**104,089**	*2,297,853*
1032	DISTRIBUTION SERVICE @ GENERATION LEVEL	D60	2,272,090	**93,143**	*2,178,947*
1033					
1034	ENERGY RELATED MWH				
1035	GENERATION LEVEL (PSP)	E10	15,324,181	**709,073**	*14,615,108*
1036	CUSTOMER LEVEL	E99	13,957,948	**650,666**	*13,307,282*
1037					
1038	CUSTOMER RELATED FACTORS				
1039	369-DIRECT ASSIGNMENT	DA369	57,124,593	**2,931,869**	*54,192,724*
1040	370-DIRECT ASSIGNMENT	DA370	2,032,402	**143,545**	*1,888,857*
1041	370-AMI METERS	DA370A	53,969,519	**1,918,616**	*52,050,903*
1042	902-CUSTOMER WEIGHTED	CW902	4,026,937	**280,077**	*3,746,860*
1043	903-CUSTOMER WEIGHTED	CW903	12,988,730	**486,065**	*12,502,665*
1044	904-CUSTOMER WEIGHTED	CW904	5,029,157	**172,260**	*4,856,897*
1045	909-DIRECT ASSIGN-AVG.NO.CUST.	DA909	489,569	**18,310**	*471,259*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
1046	***TABLE 14-ALLOCATION FACTORS***				
1047					
1048	DIRECT ASSIGNMENTS				
1049	252-CUSTOMER ADVANCES	DA252	23,565,979	**27,651**	*23,538,328*
1050	350-LAND & LAND RIGHTS	DA350	792	**792**	*0*
1051	352-STRUCTURES & IMPROVEMENTS	DA352	658	**658**	*0*
1052	353-STATION EQUIPMENT	DA353	74,044	**36,494**	*37,550*
1053	354-TOWERS & FIXTURES	DA354	0	**0**	*0*
1054	355-POLES & FIXTURES	DA355	34,064	**33,630**	*434*
1055	356-OVERHEAD CONDUCTORS & DEVICES	DA356	28,221	**26,534**	*1,687*
1056	359-ROADS & TRAILS	DA359	0	**0**	*0*
1057	360LAND & LAND RIGHTS-DA	DA360	4,729,098	**135,618**	*4,593,480*
1058	360LAND & LAND RIGHTS-CIAC	DA360C	89,946	**305**	*89,641*
1059	361-STRUCTURES & IMPROVEMENTS-DA	DA361	28,653,521	**1,116,186**	*27,537,335*
1060	361-STRUCTURES & IMPROVEMENTS-CIAC	DA361C	6,129,067	**30,890**	*6,098,177*
1061	362-STATION EQUIPMENT-DA	DA362	182,594,168	**6,074,327**	*176,519,841*
1062	362-STATION EQUIPMENT-CIAC	DA362C	24,743,557	**91,357**	*24,652,200*
1063	364-POLES, TOWERS & FIXTURES-NET	DA364	221,160,174	**16,309,188**	*204,850,986*
1064	365-OVERHEAD CONDUCTORS & DEVICES-NET	DA365	118,697,239	**7,139,900**	*111,557,339*
1065	366-UNDERGROUND CONDUIT-NET	DA366	48,258,864	**675,461**	*47,583,403*
1066	367-UNDERGROUND CONDUCTORS & DEVICES-NET	DA367	188,310,616	**3,145,662**	*185,164,954*
1067	368-LINE TRANSFORMERS-NET	DA368	408,105,839	**37,014,573**	*371,091,266*
1068	371-INSTALLATIONS ON CUSTOMER PREMISES-NET	DA371	2,701,332	**230,744**	*2,470,588*
1069	373-STREET LIGHTING SYSTEMS-NET	DA373	4,301,389	**212,828**	*4,088,561*
1070	451-REVENUE - MISCELLANEOUS SERVICE	DA451	3,532,832	**77,330**	*3,455,502*
1071	454-REVENUE - FACILITIES CHARGE	DA454	6,312,816	**358,513**	*5,954,303*
1072	454-REVENUE - MISCELLANEOUS	DA454MISC	1	**1**	*0*
1073	908-OTHER CUSTOMER ASSISTANCE	DA908	5,820,531	**210,343**	*5,610,188*
1074	440-RETAIL SALES REVENUE	RETREV	852,039,782	**39,873,591**	*812,166,191*
1075	447-WHOLESALE SALES REVENUE	RESREV	0	**0**	*0*
1076	456-REVENUE - STANDBY SERVICE	DASTNBY	309,185	**0**	*309,185*
1077	440-REVENUE OFFSET FOR PLANT ADDITIONS	DAREV	1	**0**	*1*
1078	IDAHO	CIDA	1	**0**	*1*
1079	OREGON	CODA	1	**1**	*0*
1080	NET TO GROSS TAX MULTIPLIER	DA990	1.642	**1.642**	*1.642*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
1081	***TABLE 14-ALLOCATION FACTORS***				
1082					
1083	INTERNALLY DEVELOPED ALLOCATION FACTORS				
1084	PLANT - PROD,TRANS&DIST	PTD	4,110,626,321	**197,190,771**	*3,913,435,550*
1085	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	PTDCAS	72,640,032	**3,323,860**	*69,316,172*
1086	PLANT - HYDRO,OTHER,TSUBS,DSUBS&GP	P110P	1,780,556,894	**76,311,643**	*1,704,245,251*
1087	PLANT - GEN PLT (390,391,397&398)	P3908	162,147,418	**7,778,370**	*154,369,047*
1088	PLANT - PROD,TRANS,DIST&GEN	P101P	4,374,320,369	**209,840,432**	*4,164,479,936*
1089	O&M - PROD,TRANS,DIST,CUST ACCT&CSIS	SUBEX	566,918,296	**26,053,730**	*540,864,566*
1090	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	RELAB	1,780,556,894	**76,311,643**	*1,704,245,251*
1091	LAB - ALL LABOR WITHOUT 925-6 "CIRC"	LABOR	113,958,808	**5,213,852**	*108,744,956*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
1092	***TABLE 15-ALLOCATION FACTORS-RATIOS***				
1093					
1094	CAPACITY RELATED KW				
1095	PRODUCTION RELATED COINCIDENT PEAKS @ GEN	D10	100.00%	**4.33%**	*95.67%*
1096	SYSTEM TRANSMISSION SERVICE @ GENERATION I	D11	100.00%	**4.33%**	*95.67%*
1097	RETAIL TRANSMISSION SERVICE @ GENERATION LEVE	D12	100.00%	**4.33%**	*95.67%*
1098	DISTRIBUTION SERVICE @ GENERATION LEVEL	D60	100.00%	**4.10%**	*95.90%*
1099					
1100	ENERGY RELATED MWH				
1101	GENERATION LEVEL (PSP)	E10	100.00%	**4.63%**	*95.37%*
1102	CUSTOMER LEVEL	E99	100.00%	**4.66%**	*95.34%*
1103					
1104	CUSTOMER RELATED FACTORS				
1105	369-DIRECT ASSIGNMENT	DA369	100.00%	**5.13%**	*94.87%*
1106	370-DIRECT ASSIGNMENT	DA370	100.00%	**7.06%**	*92.94%*
1107	370-AMI METERS	DA370A	100.00%	**3.56%**	*96.45%*
1108	902-CUSTOMER WEIGHTED	CW902	100.00%	**6.96%**	*93.04%*
1109	903-CUSTOMER WEIGHTED	CW903	100.00%	**3.74%**	*96.26%*
1110	904-CUSTOMER WEIGHTED	CW904	100.00%	**3.43%**	*96.57%*
1111	909-DIRECT ASSIGN-AVG.NO.CUST.	DA909	100.00%	**3.74%**	*96.26%*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
1112	***TABLE 15-ALLOCATION FACTORS-RATIOS***				
1113					
1114	DIRECT ASSIGNMENTS				
1115	252-CUSTOMER ADVANCES	DA252	100.00%	**0.12%**	*99.88%*
1116	350-LAND & LAND RIGHTS	DA350	100.00%	**100.00%**	*0.00%*
1117	352-STRUCTURES & IMPROVEMENTS	DA352	100.00%	**100.00%**	*0.00%*
1118	353-STATION EQUIPMENT	DA353	100.00%	**49.29%**	*50.71%*
1119	354-TOWERS & FIXTURES	DA354	#DIV/0!	**#DIV/0!**	*#DIV/0!*
1120	355-POLES & FIXTURES	DA355	100.00%	**98.73%**	*1.27%*
1121	356-OVERHEAD CONDUCTORS & DEVICES	DA356	100.00%	**94.02%**	*5.98%*
1122	359-ROADS & TRAILS	DA359	#DIV/0!	**#DIV/0!**	*#DIV/0!*
1123	360LAND & LAND RIGHTS-DA	DA360	100.00%	**2.87%**	*97.13%*
1124	360LAND & LAND RIGHTS-CIAC	DA360C	100.00%	**0.34%**	*99.66%*
1125	361-STRUCTURES & IMPROVEMENTS-DA	DA361	100.00%	**3.90%**	*96.10%*
1126	361-STRUCTURES & IMPROVEMENTS-CIAC	DA361C	100.00%	**0.50%**	*99.50%*
1127	362-STATION EQUIPMENT-DA	DA362	100.00%	**3.33%**	*96.67%*
1128	362-STATION EQUIPMENT-CIAC	DA362C	100.00%	**0.37%**	*99.63%*
1129	364-POLES, TOWERS & FIXTURES-NET	DA364	100.00%	**7.37%**	*92.63%*
1130	365-OVERHEAD CONDUCTORS & DEVICES-NET	DA365	100.00%	**6.02%**	*93.98%*
1131	366-UNDERGROUND CONDUIT-NET	DA366	100.00%	**1.40%**	*98.60%*
1132	367-UNDERGROUND CONDUCTORS & DEVICES-NET	DA367	100.00%	**1.67%**	*98.33%*
1133	368-LINE TRANSFORMERS-NET	DA368	100.00%	**9.07%**	*90.93%*
1134	371-INSTALLATIONS ON CUSTOMER PREMISES-NET	DA371	100.00%	**8.54%**	*91.46%*
1135	373-STREET LIGHTING SYSTEMS-NET	DA373	100.00%	**4.95%**	*95.05%*
1136	451-REVENUE - MISCELLANEOUS SERVICE	DA451	100.00%	**2.19%**	*97.81%*
1137	454-REVENUE - FACILITIES CHARGE	DA454	100.00%	**5.68%**	*94.32%*
1138	454-REVENUE - MISCELLANEOUS	DA454MISC	100.00%	**100.00%**	*0.00%*
1139	908-OTHER CUSTOMER ASSISTANCE	DA908	100.00%	**3.61%**	*96.39%*
1140	440-RETAIL SALES REVENUE	RETREV	100.00%	**4.68%**	*95.32%*
1141	447-WHOLESALE SALES REVENUE	RESREV	#DIV/0!	**#DIV/0!**	*#DIV/0!*
1142	456-REVENUE - STANDBY SERVICE	DASTNBY	100.00%	**0.00%**	*100.00%*
1143	440-REVENUE OFFSET FOR PLANT ADDITIONS	DAREV	100.00%	**0.00%**	*100.00%*
1144	IDAHO	CIDA	100.00%	**0.00%**	*100.00%*
1145	OREGON	CODA	100.00%	**100.00%**	*0.00%*
1146	NET TO GROSS TAX MULTIPLIER	DA990	1.642	**1.642**	*1.642*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
OREGON REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2011

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	*OTHER*
1147	***TABLE 15-ALLOCATION FACTORS-RATIOS***				
1148					
1149	INTERNALLY DEVELOPED ALLOCATION FACTORS				
1150	PLANT - PROD,TRANS&DIST	PTD	100.00%	**4.80%**	*95.20%*
1151	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	PTDCAS	100.00%	**4.58%**	*95.42%*
1152	PLANT - HYDRO,OTHER,TSUBS,DSUBS&GP	P110P	100.00%	**4.29%**	*95.71%*
1153	PLANT - GEN PLT (390,391,397&398)	P3908	100.00%	**4.80%**	*95.20%*
1154	PLANT - PROD,TRANS,DIST&GEN	P101P	100.00%	**4.80%**	*95.20%*
1155	O&M - PROD,TRANS,DIST,CUST ACCT&CSIS	SUBEX	100.00%	**4.60%**	*95.40%*
1156	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	RELAB	100.00%	**4.29%**	*95.71%*
1157	LAB - ALL LABOR WITHOUT 925-6 "CIRC"	LABOR	100.00%	**4.58%**	*95.42%*

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MATTHEW T. LARKIN

July 29, 2011

Q. Please state your name and business address.

A. My name is Matthew T. Larkin 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 ("Idaho Power" or "Company") as a Regulatory Analyst in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration degree in Finance from the University of Oregon in 2007. In 2008, I earned a Master of Business Administration degree from the University of Oregon. I have also attended electric utility ratemaking courses including "The Basics: Practical Regulatory Training for the Electric Industry," a course offered through New Mexico State University's Center for Public Utilities, and Introduction to "Rate Design and Cost of Service Concepts and Techniques," presented by Electric Utilities Consultants, Inc.

Q. Please describe your work experience with Idaho Power.

A. I began employment with Idaho Power as a Regulatory Analyst in January 2009. As a Regulatory Analyst, I provide support for the Company's various regulatory activities, including regulatory reporting, financial analysis, and the development of various cost-related studies. During my time with the Company, I have assisted in the preparation of the Company's Oregon Results of Operations Report, retail revenue forecasts for regulatory filings, and a number of cost-of-service studies.

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

A. My testimony will address the derivation of the Company's 2011 Test Year retail revenue forecast, the "functionalization" of the proposed Oregon jurisdictional revenue requirement provided to me by Ms. Kelley Noe, the 2011 Marginal Cost

Analysis, and the proposed allocation of the Oregon jurisdictional revenue requirement.

Q. Have you prepared any exhibits as part of your testimony?

A. Yes. I have prepared the following seven exhibits as part of my testimony:

1. Exhibit 1001 describes the methodology used to develop the Oregon class-specific test year customer and energy forecasts
2. Exhibit 1002 is a summary of the 2011 Test Year retail revenue forecast
3. Exhibit 1003 presents the calculation of the 2011 Test Year retail revenue forecast
4. Exhibit 1004 presents the Company's functionalized revenue requirement
5. Exhibit 1005 is the 2011 Marginal Cost Analysis ("2011 Analysis")
6. Exhibit 1006 is a summary of marginal costs by customer class, the resulting revenue requirement allocation, and the class-specific unit costs
7. Exhibit 1007 details the Company's proposed revenue requirement allocation.

I. <u>2011 TEST YEAR RETAIL REVENUE DERIVATION</u>

Q. Please provide a brief description of the methodology used to determine test year retail revenues.

A. Generally speaking, the Company's retail revenue forecast is derived by applying current base rates to forecasted test year billing components. These billing components are derived by applying historical relationships to the Company's customer and kilowatt-hour ("kWh") sales forecast.

Q. Were the 2011 Test Year retail sales revenues developed using the same methodology applied in the Company's last general rate case, Docket No. UE 213 ("2009 Rate Case")?

A. Yes. With the exception of a minor change in the manner in which the demand-related billing determinants were developed-- which I will describe later in my testimony-- the methodology applied in this case is the same as that applied in the 2009 Rate Case.

Q. Please describe the customer and kWh sales forecast that serves as the basis for the 2011 Test Year retail revenue forecast.

A. The 2011 Test Year customer and kWh sales forecast is based upon the Sales and Load Forecast prepared for the 2011 Integrated Resource Plan ("IRP") filed with the Commission in June 2011. Because the IRP Sales and Load Forecast is developed on a system-wide basis, an additional step must be taken to determine the class-specific customer and energy values by jurisdiction. Once the monthly sales estimates have been developed for each customer class, they must be further segmented to align with each class's rate structure.

The methodology used to develop the Oregon class-specific test year customer and energy values is outlined in the document Development of Sales Forecast for Revenue Calculation, as Exhibit 1001 to my testimony. The described forecasting methodology results in class customer counts and total kWh sales estimates for each month of the test period. As Exhibit 1001 states, the IRP Sales and Load Forecast has been modified for the purpose of this filing to exclude the new large load customer expected to begin taking service in the Company's Oregon jurisdiction in late 2011. While the inclusion of this large load is necessary for planning purposes, it is not appropriate to be included in the ratemaking process prior to the finalization of a contractual agreement between the Company and the new large load customer.

Q. How were the 2011 Test Year kWh sales further segmented into the class-specific energy-related billing components?

A. The first step in deriving energy-related billing components for the test year is to develop factors based on the most current complete calendar year of available historical data, which in this case is 2010. These historical factors represent the percentage of total kWh billed in each tier level of a class's rate structure. To illustrate, Small General Service customers taking service under Schedule 7 are billed according to a two-tiered structure with seasonal rate differentiation. Using the historical month of June 2010 as an example, actual tiered usage was recorded at the following levels for Schedule 7 customers in the Oregon jurisdiction:

Usage Tier	**June 2010 Schedule 7 Billing Components**
Summer, 0-500 kWh	202,487
Summer, Over 500 kWh	166,921
Non-Summer, 0-500 kWh	422,867
Non-Summer, Over 500 kWh	348,592
Total Schedule 7 kWh Usage	**1,140,867**

Based on the data above, historical factors for Schedule 7 customers for the month of June were calculated as follows:

Usage Tier	**June 2010 Schedule 7 Weighting Factors**
Summer, 0-500 kWh	17.75%
Summer, Over 500 kWh	14.63%

Non-Summer, 0-500 kWh	37.06%
Non-Summer, Over 500 kWh	30.56%
Total Schedule 7	**100.00%**

This process is used to develop historical factors for all rate classes with tiered structures. Once a complete set of monthly factors has been developed for each applicable rate class, they are applied to monthly forecast kWh totals to derive the energy-related billing component forecast that aligns with each class's current rate structure. Continuing with the illustration of Schedule 7 customers, the following table demonstrates the final step in determining test year energy-related billing components:

Usage Tier	Historical June Weighting Factor	June 2011 Schedule 7 Billing Component Forecast (kWh)
Summer, 0-500 kWh	17.75%	223,654
Summer, Over 500 kWh	14.63%	184,370
Non-Summer, 0-500 kWh	37.06%	467,073
Non-Summer, Over 500 kWh	30.56%	385,034
Total Schedule 7 kWh Usage	**100.00%**	**1,260,131**

Q. How are demand-related billing components derived based on the kWh sales forecast?

A. The demand-related billing components consist of billing demand and basic load capacity ("BLC") by month for each rate class. Both billing demand and BLC totals are forecasted by applying four-year average load factors to each month in the kWh sales forecast. Historical data from the most current available four calendar years is used to derive an average load factor by month for each rate class. These average factors are then applied to monthly kWh sales figures to determine total forecasted billing demand and BLC by class for each month of the test period. The use of four-year average load factors is a departure from the methodology applied in the 2009 Rate Case, which calculated load factors based on the most current available single year of data. This adjustment reduces the impact of fluctuations within a single year on the derivation of test year demand-related billing components. Once monthly totals have been developed, they are divided into the appropriate tiered rate structure (if applicable) utilizing historical factors in the same manner as kWh charges.

Q. How are customer-related billing components derived based on the customer count forecast?

A. The primary customer-related billing component in the retail revenue forecast is the service charge. Because the customer forecast reflects the expected number of customers under active Utility Service Agreements ("USA") at the end of each forecast month, forecast values must be converted to reflect the expected number of service charges received throughout the corresponding month. To convert the USA forecast to an expected service charge count, historical factors are developed reflecting the relationship between the number of USAs at the end of each historical month and the number of service charges received during the corresponding month. These factors are then applied to the monthly customer forecast to develop a forecast of expected service charges by rate class for each month of the test year.

Q. How are test year retail revenues calculated once the billing component forecast has been derived?

A. Once the billing components have been forecasted by rate class, the most currently approved base rates are applied to the test year component values to derive monthly revenue forecasts for each rate class.

Q. Have you prepared any exhibits that detail the calculations that were made to determine the Company's 2011 Test Year retail revenues?

A. Yes. Exhibit 1002 provides a summary of forecasted 2011 Test Year retail revenues, and Exhibit 1003 details the calculations that were made to determine these revenues. Input data used in the forecast calculations can be found in my workpapers. As can be seen on page 4 of Exhibit 1002, the Company's 2011 Oregon jurisdictional retail sales revenues are forecast to be $39.9 million.

II. FUNCTIONALIZATION OF REVENUE REQUIREMENT

Q. Please explain the meaning of functionalization.

A. Before the Company's proposed revenue requirement can be divided among customer classes, costs must be functionalized – that is, identified with utility operating functions. Operating functions recognize the different roles played by the various facilities in the electric utility system. In the Company's accounts, these various roles are recognized to some degree, particularly in the recording of plant costs as generation-, transmission-, or distribution-related. However, this functional breakdown is not sufficiently detailed for cost-of-service purposes.

Q. How are costs further segmented for cost-of-service purposes?

A. For cost-of-service purposes, functionalized costs are further segmented or "classified" as energy-, demand- or customer-related. Energy-related costs are generally the variable costs associated with the operation of the generating plants, such as fuel. However, because the Company is heavily reliant on hydro generation, a portion of the hydro and thermal generating plant investment has been classified as energy-related according to the Company's system load factor. Demand-related costs are investments in generation, transmission, and distribution plant capacity and the associated operation and maintenance expenses necessary to accommodate the maximum demand imposed on the Company's system. Examples of customer related costs are the plant investments and expenses that are associated with meters and service drops, meter reading, billing and collection, and customer information and services, as well as a portion of the investment in the distribution system. These investments and expenses are made and incurred based on the number of customers, regardless of the amount of energy used, and are therefore generally considered to be fixed costs.

Q. Please describe in general terms the process used to functionalize and classify the Company's revenue requirement.

A. In the functionalization process, individual plant items, operations and maintenance expenses, and other operating revenues are examined and, where possible, the associated costs and revenues are assigned to one or more operating functions. The remaining costs and revenues are allocated to each functional category according to the appropriate allocation basis. Generation costs are further classified as either demand- or energy-related, transmission costs are classified as demand-related, and distribution costs are classified as either demand- or customer-related. The following example illustrates this process: for Accounts 310 through 316, Steam Production, the Company's investment in steam production plant is assigned to the production or generation function and to the demand and energy cost classifications. The resulting functionalization and classification of costs may itself serve as a basis for subsequent allocations. This use is illustrated where the accumulated depreciation for steam production plant is functionalized and classified on the same basis as steam plant investment.

Q. Has the Company classified transmission-related investment in a manner consistent with the methodology used in the 2009 Rate Case?

A. Yes. Transmission-related investment has been classified as 100 percent demand-related according to the Company's traditional approach. In the settlement stipulation to the 2009 Rate Case, the Company agreed to the classification of transmission-related revenue requirement as 75 percent demand-related and 25 percent energy-related. While the Company agreed to this one-time adjustment for use in the settlement stipulation, it believes that classifying transmission-related investment as 100 percent demand-related results in a more appropriate allocation of transmission-related costs.

Q. Please describe Exhibit 1004.

A. Exhibit 1004 details the development of the Company's functionalized revenue requirement for each of the following categories: (1) generation, (2) transmission, and (3) distribution. As can be seen on Exhibit 1004, the total Oregon jurisdictional revenue requirement of $45,721,417 has been segmented into the Company's three main operating functions. Generation-related revenue requirement represents approximately $25.8 million or 56.4 percent of the total; transmission represents approximately $4.6 million or 10 percent; and distribution represents $15.3 million or 33.6 percent.

III. 2011 MARGINAL COST ANALYSIS

Q. What methodology was used to allocate the proposed revenue requirement to customer classes in this general rate case proceeding?

A. The proposed revenue requirement has been apportioned to customer classes according to the Company's 2011 Marginal Cost Analysis. In general terms, this analysis calculates the marginal cost associated with supplying an added unit of electricity or serving an additional customer. A detailed description of the 2011 Marginal Cost Analysis and supporting schedules showing the development of the marginal costs is provided in Exhibit 1005.

Q. Please summarize the 2011 Marginal Cost Analysis, which is described in greater detail in Exhibit 1005.

A. The 2011 Marginal Cost Analysis was prepared according to concept and design specifications of the National Economic Research Associates, Inc. ("NERA") marginal cost model. The NERA model is constantly being refined but the basic concepts and methods have remained the same since Idaho Power began using this method. The analysis identifies the long-run marginal cost of providing electric service to new load on the Idaho Power Company system. The Company's forecasted growth-related generation, transmission, and distribution costs are identified and classified into the appropriate energy-, demand-, and customer-related components in a manner similar to the classification of the Oregon jurisdictional revenue requirement.

The energy-related marginal costs include net power supply costs, variable operation and maintenance ("O&M") expenses, fuel inventory, and losses. Demand-related costs are comprised of generation, transmission, and distribution investment and associated fixed O&M expenses. Customer-related costs include investment costs that are attributable to anticipated growth in the number of customers served. In this analysis, marginal unit costs are prepared for each functional category for use in apportioning the revenue requirement to customer classes.

Q. How does the 2011 Marginal Cost Analysis compare to the analysis filed in the Company's last general rate case proceeding, Docket No. UE 213?

A. The 2011 Marginal Cost Analysis was prepared according to the same methodology used to prepare the 2009 Marginal Cost Analysis ("2009 Analysis") filed in Docket No. UE 213. A comparison of the numerical results of the 2011 and 2009 Analyses is provided later in my testimony.

Q. Please explain how the generation marginal costs for the energy- and demand-related categories were determined.

A. Generation energy-related marginal costs were determined by a simulated operation of the Company's power supply system over 83 streamflow conditions for the five year period 2011 through 2015 using the Company's AURORA Power Supply Model. Base case net power supply expenses were quantified and the model was run a second time with 50 megawatts ("MW") of load added across all hours. The difference in monthly power supply expenses between the base run and the "base-plus-50-MW run" was averaged over the five year period and was divided by the difference in monthly megawatt hours ("MWh") to produce an average monthly marginal cost per megawatt hour.

Generation demand-related marginal costs are based upon the levelized cost of a simple-cycle combustion turbine from Idaho Power's 2011 IRP. The peaking resource selected from the resource portfolio to quantify the marginal generation capacity cost is the Danskin CT1 Combustion Turbine. This resource is the latest peaking resource addition to the Company's rate base. The generation capacity marginal costs are then seasonalized based on the monthly peak hour load surplus/deficiency data, assuming 90th percentile streamflow conditions, 70th percentile average load, and 95th percentile peak-hour load contained in the 2011 IRP.

Q. Please explain how the transmission marginal costs were determined.

A. The marginal cost of transmission reflects planned investment in transmission plant for a ten-year period, 2011 through 2020. Demand-related transmission O&M costs were estimated using historic data for the period 2006 through 2010. Transmission marginal costs were seasonalized in a manner similar to that used to seasonalize the generation capacity marginal costs.

Q. Please provide an overview of how the distribution marginal costs were determined.

A. The distribution marginal costs were developed according to NERA's facilities cost approach. Under this method, distribution costs are divided into three categories: (1) costs that increase due to growth in actual peak demand, (2) design demand-related costs, and (3) customer-related costs. According to the NERA model, design demand-related costs are those costs that are considered fixed over time because they do not change in response to customers' actual loads. Design demand-related costs are incurred on the basis of the planner's engineering design standards, which reflect the number of customers to be served, and the expected maximum demand of those customers, rather than on changes in actual peak demand.

The first category of costs, those that increase due to growth in actual peak demand, is comprised of distribution substation carrying costs and related O&M expense. The second category of costs is comprised of the carrying costs of the plant located between the substation and the service drop, and the associated O&M expense. This includes primary lines, secondary lines, poles, transformers, and associated equipment. Customer-related costs include the carrying cost of the service drop, customer service and informational expense, and customer accounting expense. Customer service and informational expense refers to those expenses included in FERC Accounts 907 through 910 and customer accounting expense refers to those expenses included in FERC Accounts 901 through 905. The service drop is considered by NERA to be part of the design demand-based category, but Idaho Power's practice has been to include the service drop as part of the customer-related category, as it has been done in this analysis.

Q. Please describe page 30 of Exhibit 1005, Schedule 16.

A. Page 30 of Exhibit 1005, Schedule 16, presents the results of the 2011 Marginal Cost Analysis. The analysis results are presented in terms of marginal unit costs for each customer class. The marginal unit cost values for the generation and transmission functional categories are provided as monthly values and the distribution-related marginal unit costs are provided as annual values. The distribution-related marginal costs reflect the attribution of primary and secondary distribution costs to the appropriate classes depending on the voltage level of service (primary, secondary, or transmission).

Q. Why are monthly marginal unit cost values provided for the generation and transmission functional categories, while only annual values are provided for the distribution category?

A. Marginal unit costs are prepared as either monthly or annual values in order to align with the associated allocation basis. Marginal unit costs are developed for the purpose of determining the total marginal costs by functional category by customer class. In this analysis, the total marginal costs by customer class were determined by multiplying the marginal unit costs for each functional category by the appropriate allocation basis for each customer class; i.e., energy, demand, or number of customers. For example, the total generation and transmission capacity marginal costs for each class were determined by multiplying each class's 12 monthly coincident peak demand values by the corresponding monthly marginal unit cost. Similarly, the total energy-related generation marginal costs for each class were determined by multiplying each class's monthly energy values by the corresponding monthly marginal unit cost. The marginal unit costs for the generation and transmission functional categories are prepared as monthly values to recognize that those cost categories vary by month and, to a greater extent, seasonally.

Consistent with that rationale, the distribution marginal unit costs have been prepared as annual values in order to recognize that distribution costs do not vary by month or seasonally to the extent of the other functional categories. The total distribution demand-related marginal costs by customer class were determined by applying the class-specific distribution demand-related marginal unit cost to the single highest monthly non-coincidental peak demand value for each customer class. Similarly, the total distribution customer-related marginal costs by customer class were determined by applying the class-specific distribution customer-related marginal unit cost to the corresponding annual customer counts for each class. The use of annual values in the case of distribution costs achieves the goal of aligning the marginal unit costs with the associated allocation basis.

Q. Has the Company made any modifications to the derivation of test year coincident peak demand values for use in the calculation of total marginal costs?

A. Yes. The Company has modified the derivation of test year coincident peak demand values to address the potential effect of the Company's Demand Response ("DR") programs on the revenue requirement allocation process.

Q. Please provide a brief description of each of the DR programs that will be operated by the Company during 2011.

A. In 2011, the Company will operate three separate DR programs: Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management. Irrigation Peak Rewards is a DR program available to agricultural irrigation customers. A/C Cool Credit is a DR program available to residential customers in select areas within the Company's service area where the necessary communication technology is available. FlexPeak Management is a DR program available to larger commercial and industrial customers. These programs have allowed the Company to successfully and cost-effectively reduce load during the summer afternoon hours when demand for electricity is highest.

Q. Why is it necessary to adjust coincident peak demands to account for reductions from DR programs?

A. As my testimony states, each class's 12 monthly coincident peak demand values are multiplied by the corresponding monthly marginal unit cost for the purpose of allocating a portion of the demand-related revenue requirement. When DR programs reduce demand at the time of the system peak, they have the potential to reduce the participating class's coincident peak demand values, subsequently reducing its allocation of any coincident peak demand-related revenue requirement. As a result, classes without DR programs in effect during the system's peak hour could receive a higher revenue requirement allocation when DR programs successfully reduce peak hour demand.

Q. Could this result in inequitable revenue requirement allocation?

A. Yes. DR programs are intended to generate cost savings during system peak hours by reducing demand, thus avoiding or reducing the need to acquire more costly supply-side resources. In this sense, they are operated in the same manner as traditional supply-side resources. With respect to the cost-of-service study, the Company's resource selection should not unduly affect the allocation of revenue requirement among customer classes. If the effects of DR programs are not accounted for, revenue requirement allocation can potentially be skewed when demand reductions are achieved during peak hours. If no adjustments are made, coincident peak demand-related allocation can potentially shift revenue requirement solely based on the Company's choice to utilize a demand-side resource over traditional supply-side resources.

Further, the Company's DR programs provide a financial incentive to participants in exchange for temporary load reduction. Any revenue requirement allocation benefits received from DR program reductions that are not accounted for in the initial incentive design provide the potential for an unintended benefit to participating rate classes at the expense of non-participating rate classes. These allocation benefits are also received by all customers of a participating rate class, although not all customers within each rate class participate in DR programs, resulting in the potential for non-participating customers to receive a benefit without providing any load reduction in return.

Finally, the costs of the Company's DR programs are spread among all rate classes. The successful operation of these programs results in system cost savings by avoiding more expensive supply-side resources. Without adjustment, demand reductions during the time of the system peak can potentially lower revenue requirement allocation to participating classes while increasing allocation to other classes. This creates the potential for rate classes to contribute to the funding of DR programs, while at the same time receiving a higher revenue requirement allocation when the programs are successful.

Q. Please describe the methodology used to adjust the coincident peak demand values to better reflect the impact that the DR programs have on the Company's peak demands.

A. The method for estimating system coincident demands utilizes system coincident demand factors, which represent the ratio of the system coincident demand to the average demand. To derive the monthly system coincident demands, monthly 2010 factors derived from historical load research data are applied to the associated population's monthly average demands for the test year.

To remove the potential for inequitable cost allocation due to the effect of the DR programs, the Company's proposed method derives system coincident demand factors as if no DR programs had been in effect during the historical data period. In doing so, DR programs receive equal treatment to the Company's supply-side resources, removing the potential for resource selection to unduly affect the revenue requirement allocation process.

To accomplish this, historical load data was adjusted to reflect system loads that would have occurred had no DR programs been in effect. This adjustment was made by adding back estimated demand reductions achieved through the respective DR programs to historical hourly system loads. The resulting load shape reflects system loads that the Company's supply-side resources would have been required to meet without the availability of demand-side resources. The adjusted data was then used to determine the hour that the system peak would have occurred absent DR programs, and system coincident demand factors were calculated according to the adjusted peak hour and historical usage data. Finally, these factors were applied to forecast average demand to derive coincident peak demands by rate class for each month of the test period. A detailed description of the coincident peak demand derivation process is provided in the document Peak Responsibility Methods for the 2011 General Rate Case, provided in my workpapers.

Q. How did the Company arrive at its proposed methodology?

A. The effect of DR programs on the derivation of coincident peak demands was discussed with subject matter experts throughout the Company in Load Research, Regulatory Affairs, Energy Efficiency, and Power Supply Planning. The issue was also discussed with the well-respected industry consultant Global Energy Partners, LLC, which published a research document titled, *Demand Response: It's A Resource, So Treat It Like One*. This document suggests treating DR programs in the same manner as supply-side resources in the derivation of coincident peak demands. The Company's proposed methodology aligns with this suggested treatment, and represents the consensus following extensive internal discussion.

Q. Idaho Power submitted a Marginal Cost Analysis as part of the 2009 Rate Case. How do the results of the current analysis compare to the results of the 2009 Rate Case Analysis?

A. The 2011 Analysis results are comparable to the results of the 2009 Analysis with the exception of a few areas.

From the 2009 Analysis to the 2011 Analysis, average annual energy costs decreased from $60.31 per MWh to $39.85 per MWh. A primary cause of this reduction is a change in the projected dispatch of the Company's coal-fired power facilities between the 2009 and 2011 IRPs. As stated on page 96 of the 2009 Integrated Resource Plan ("2009 IRP"), the potential cost of carbon emissions in the 2009 edition was treated differently than in previous plans. Prior to the 2009 plan the Company utilized a carbon adder, or tax, in its power supply modeling to reflect the costs associated with possible carbon regulation. For the 2009 IRP, however, the Company utilized a forced coal curtailment strategy to reflect the provisions of the Waxman-Markey bill, which had been passed by the House of Representatives but not yet debated in the Senate at the time of the 2009 IRP filing. Due to the subsequent failure of the Waxman-Markey bill, the Company returned to its previous method of utilizing a carbon adder in power supply modeling in the 2011 IRP, increasing the projected dispatch of relatively low-cost coal-fired facilities. Consequently, the marginal cost of energy decreased due to the added availability of coal-fired resources.

Annual generation capacity costs as computed in the 2009 Analysis were $45 per kilowatt ("kW") in 2009 dollars, while in the current analysis the costs have declined to $38 per kW in 2010 dollars. A portion of the decline in marginal capacity cost is the result of a reduction in the Company's requested return on equity ("ROE") between the 2009 and 2011 general rate case filings. In the 2009 case, the Company requested an ROE of 11.25%, while in the 2011 filing the Company is requesting an ROE of 10.50%. The lower requested ROE results in lower carrying costs, which in turn result in lower annual costs associated with generation capacity.

The cost of annual transmission capacity was $173 per kW in the 2009 Analysis and is now $150 per kW in the current analysis. This change is due to two primary factors. First, annual transmission capacity costs were affected by the lower requested ROE of 10.50% in the same manner as annual generation capacity costs, reducing associated economic carrying charges resulting in lower overall annual costs. Second, the 2011 Analysis reflects lower transmission investment associated with the integration of new resources. In the 2009 Analysis, the forward-looking five-year planning period included four years of investment associated with the integration of the gas-fired Langley Gulch power plant, totaling approximately $32 million in investment from 2009 through 2012. In the 2011 Analysis much of this investment has already taken place, with only two years of investment occurring in the forward-looking five-year planning period, totaling approximately $18 million from 2011 through 2012.

The marginal cost of distribution substation capacity was $18.80 per kW in the 2009 Analysis and is $11.00 per kW in the current analysis. This reduction in the marginal cost can be attributed largely to a lower five-year budget forecast of growth-related distribution substation investment. The 2009 Analysis contained a five-year budget of approximately $54 million, while the 2011 Analysis reflects a five-year budget of approximately $37 million. The budget included in the 2011 Analysis is lower than the 2009 Analysis due to a number of factors, which include a large project that was customer-funded, the acceleration of a number of projects that were completed in 2010 rather than 2011 or beyond, the replacement of a number of projects by large distribution projects which shifted them out of the stations budget and into the distribution capital spend, and the delay of a number of projects until 2016 and beyond due to the current condition of the economy.

Distribution facilities investment costs ranged from $17.95 per kW to $54.88 per kW in the 2009 Analysis. In the current analysis, these costs ranged from $15.45 per kW to $44.27 per kW. Distribution customer-related costs ranged from $87.15 per customer to $3,165.74 per customer in the 2009 Analysis. In the current analysis, these costs ranged from $76.09 per customer to $2,534.67 per customer.

Overall, the results of the 2011 Analysis appear reasonable when compared to the 2009 Analysis, especially when considering the changes in circumstances as described above.

IV. MARGINAL COST-BASED REVENUE REQUIREMENT ALLOCATION

Q. Once the marginal costs for each functional category were determined, how were those marginal costs utilized to allocate the Oregon jurisdictional revenue requirement to each customer class?

A. Exhibit 1006 presents the total marginal cost by customer class and by functional category resulting from the 2011 Analysis. As can be seen on page 1 of Exhibit 1006, the total functionalized revenue requirement from Exhibit 1004 has been allocated to each customer class in proportion to the marginal cost by class for each functional category. This allocation represents the Company's quantification of the cost of providing service to each customer class, or the "cost-of-service." The total marginal costs exceed the Oregon jurisdictional revenue requirement and are not the basis of recovery from classes, but rather are utilized to determine each class's responsibility or share of the total Oregon jurisdictional revenue requirement.

Pages 2 through 5 of Exhibit 1006 present the class-specific units costs. The class-specific unit costs represent the revenue requirement by billing unit for each customer class. The unit costs ultimately help guide the rate design process by providing a cost-of-service basis for each rate component.

Q. Has the Company allocated generation-related investment in a manner consistent with the methodology used in the 2009 Rate Case?

A. Yes. The energy-related and demand-related portions of embedded generation costs were allocated separately based on their respective marginal costs according to the Company's traditional approach. In the settlement stipulation to the 2009 Rate Case, the Company agreed to a one-time adjustment to not divide embedded generation costs into energy-related and demand-related portions prior to class allocation. While the Company agreed to this one-time adjustment for use in the settlement stipulation, it believes that blending these costs prior to class allocation reduces the level of accuracy of the allocation process. By combining these costs, class allocation is disconnected from the corresponding cost drivers, resulting in the potential to allocate costs disproportionately to cost responsibility.

Q. Line 26, page 1 of Exhibit 1006 presents the "Direct Assignment" of a portion of the customer-related distribution costs. What portion of the Company's revenue requirement has been directly assigned to customer classes on line 26?

A. The revenue requirement amount on line 26, page 1 of Exhibit 1006 is comprised of rate base associated with FERC Accounts 371 and 373 and expenses associated with FERC Accounts 585, 587, and 598. The revenue requirement amount on line 26 is largely associated with expenses related to rendering services at customers' premises. Examples of such services include inspecting customers' premises, installing, testing, and removing leased equipment, and testing customer-owned equipment. The remainder of the revenue requirement on line 26 is associated with the Company's lighting service customer classes.

Q. Please describe the results of the marginal cost-based revenue requirement allocation presented on Exhibit 1006.

A. As can be seen on Exhibit 1006, a pure marginal cost-based allocation of the Oregon jurisdictional revenue requirement results in increases of 18.75 percent for Residential Service, 2.10 percent for Small General Service, 8.31 percent for Large General Service – Secondary Voltage Level, 2.59 percent for Large General Service – Primary Voltage Level, -26.72 percent for Large General Service – Transmission Voltage Level, -6.53 percent for Area Lighting Service, -2.50 percent for Large Power Service – Primary Voltage Level, 15.08 percent for Large Power Service – Transmission Voltage Level, 61.28 percent for Irrigation Service, 13.57 percent for Unmetered General Service, 1.01 percent for Municipal Street Lighting Service, and 55.42 percent for Traffic Control Lighting Service.

V. PROPOSED REVENUE REQUIREMENT ALLOCATION

Q. What is the Company's general philosophy on revenue requirement recovery from customer classes?

A. The Company's primary approach to revenue requirement allocation in the last several general rate cases has been to establish class revenue requirements that as accurately as possible reflect the costs of serving those customer classes. Accordingly, the Company's ratemaking proposals generally advocate movement towards the cost-of-service results, which assign costs to those customer classes that cause the Company to incur the costs.

Q. Are there other objectives that may be considered in the ratemaking process?

A. Yes. The Commission may consider a number of other objectives, such as rate stability, in the determination of rates.

Q. How did you approach the determination of the Company's proposed revenue requirement for each customer class?

A. A pure marginal cost-based revenue requirement spread would result in substantial increases to Irrigation Service and Traffic Control Lighting Service. In order to mitigate the magnitude of the rate increase to each of these customer classes that would be necessary to bring them to current cost-of-service levels, the Company is proposing to cap the percentage increase for Irrigation Service and Traffic Control Lighting Service at two-times the average overall requested increase, or 29.34%. Furthermore, a pure marginal cost-based revenue requirement spread would result in decreases for Large General Service – Transmission Voltage Level, Area Lighting Service, and Large Power Service – Primary Voltage Level. For these classes, the Company proposes to apply a 0.00 percentage change “floor” resulting in neither an increase nor a decrease.

Q. Did you discuss the results of the cost-of-service study internally before deciding to apply the caps and floors to the specified customer classes?

A. Yes. I discussed the results of the cost-of-service study and potential rate spread scenarios with Mr. Gregory W. Said, who is responsible for the overall preparation of this case. My revenue requirement allocation recommendation is a result of those discussions.

Q. Do you have an exhibit that details the class revenue requirement determination?

A. Yes. Exhibit 1007 is a four-page exhibit that steps through the revenue requirement allocation process from the cost-of-service results to the ultimate proposal for each customer class. Page 1 of Exhibit 1007 is the pro forma normalized test year sales and revenues. Page 2 details the results from the cost-of-service study and illustrates the revenue changes that would be made to each customer class to obtain the cost-of-service results. Page 3 shows the revenue shortfall that resulted by applying the caps and floors to the specified customer classes. Finally, page 4 shows the proposed increase to the other customer classes which resulted from spreading the shortfall created by the mitigation to the remaining classes in order to obtain the total Oregon jurisdictional target revenue requirement. I have provided the results from page 4 to Mr. Scott Sparks and Ms. Darlene Nemnich and their Rate Design Team for use in determining the individual rates for the Company's general tariff customers.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Matthew T. Larkin
Development of Sales Forecast for Revenue Calculation

July 29, 2011

IDAHO POWER®
An IDACORP Company

Date: February 18, 2011

To: Tim Tatum

From: Barr Smith

Subject: Development of Sales Forecast for Revenue Calculation

Energy and Customer Forecast Development

The process used to develop future year energy and customer counts by rate schedule and jurisdiction has two distinct steps. In the first step, sales and customer forecasts are developed on a system-wide basis for each major customer segment or class; i.e., residential, commercial, industrial, irrigation and special contracts. In the second step, the sales and customer forecasts developed in the first step are allocated to each individual service schedule or rate schedule. The allocation basis used for each customer class forecast is the most current historical year's weather normalized electricity sales (also referred to as weather-adjusted sales); in this case 2010 was used. The historical 2010 weather-adjusted sales, available by rate schedule and jurisdiction, are used *only* to allocate the system class-level forecasts to rate schedule and jurisdiction. The regression equations used to weather-normalize historical electricity sales are not used in the long-term forecasts of electricity sales.

Sales Forecasting Process

System Sales Forecast Development by Class

A long-term sales forecast is prepared, typically once each year, for each customer class: residential, commercial, industrial, and irrigation, as well as for each special contract customer. The sales forecast process is described in detail in *Appendix A – Sales and Load Forecast for the Integrated Resource Plan* (IRP), filed June 2011.

The sales forecast models are driven by the most recent available economic forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, a national econometric consulting firm. Moody's Analytics July 2010 macroeconomic forecast was used to develop the August 2010 forecast for the 2011 IRP. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. National economic drivers from Moody's Analytics were also used in development of the most recent sales forecast.

Economic growth assumptions influence several of the individual class of service growth rates. Because growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth, service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are used to form load projections.

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy forecasts are developed for Micron Technology, Simplot Fertilizer, the Idaho National Laboratory (INL), and Hoku Materials, Inc. (Hoku). The assumptions for each of the individual categories are described in greater detail in their respective sections in *Appendix A –Sales and Load Forecast for the Integrated Resource Plan*. System residential sales are a function of a number of factors affecting electricity sales to that sector. Residential sales are a function of heating degree days (HDD) in wintertime, cooling degree days (CDD) in summertime, the number of service area households as derived from Moody's Analytics forecasts of county housing stock, the real price of electricity, and the real price of natural gas. System commercial sales are also a function of HDD, CDD, the real price of electricity, and the number of service area households, as well as service area employment as derived from Moody's Analytics forecasts. In the industrial sector forecast, regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment or population, and other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment or population drivers, resulting in the escalation of electricity sales to the various industry groups over time. The system irrigation sales forecast considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Product: Farms, for Idaho,* and the real price of electricity.

Energy Forecast Development by Jurisdiction and Rate Schedule

To accurately estimate the revenue derived from energy and apply the appropriate charges to that energy, it is necessary to develop a more-detailed energy forecast that provides a forecast of energy sales by jurisdiction and rate schedule. The models for allocating the system class-level sales forecasts (residential, commercial, industrial, and irrigation classes) to jurisdiction and rate schedule were developed as follows:

Residential Energy Forecast

The residential class includes electricity sales to customers taking service under Schedule 1 (Schedules 3, 4, and 5, inclusive) and Schedule 15. Because the residential sales forecast was developed on a system-wide basis by billing month, it was necessary to allocate the system-wide residential sales forecast to each jurisdiction and the appropriate rate schedules (Schedules 1 and 15). In this process, 2010 normalized energy was used to develop allocation factors for each jurisdiction and rate. The allocation factors were then applied to the system-wide billing month residential sales forecast (excluding Schedule 15) to determine the forecast of billing month residential sales by rate schedule and jurisdiction. This method results in Idaho jurisdiction residential sales (Schedule 1) that grow at essentially the same rate as Oregon jurisdiction residential sales. The Schedule 15 forecast energy figures in both the IPUC and OPUC jurisdictions were set to match the 2010 normalized energy figures (i.e., no sales growth). No sales growth was assumed based on an historical trend of flat /no growth from 2000 through 2010.

Commercial Energy Forecast

The commercial class includes electricity sales to customers taking service under Schedules 7, 9 (Primary, Secondary, and Transmission Service), 16, 40, 41, and 42. Because the commercial sales forecast was developed on a system-wide basis by billing month, it was necessary to allocate the system-wide commercial sales forecast to each jurisdiction and the appropriate rate schedules (Schedules 7, 9 Secondary and Primary Service). In this process, 2010 normalized energy was used to develop allocation factors for each jurisdiction and rate. The allocation factors were then applied to the system-wide billing month commercial sales forecast (excluding Schedules 16, 40, 41, and 42) to determine the forecast of billing month commercial sales by rate schedule and jurisdiction. The Schedules 9 Transmission Service, 16, 40, 41, and 42 forecast energy figures in both the IPUC and OPUC jurisdictions were set to match the 2010 normalized energy figures (i.e., no sales growth). No sales growth was assumed based on an historical trend of flat /no growth from 2000 through 2010.

Industrial Energy Forecast

The industrial class includes electricity sales to customers taking service under Schedule 19 (Primary, Secondary, and Transmission Service). Because the industrial sales forecast was developed on a system-wide basis by billing month, it was necessary to allocate the system-wide industrial sales forecast to each jurisdiction and the appropriate rate schedules (Schedules 19 Primary and Transmission Service). In this process, 2010 normalized energy was used to develop allocation factors for each jurisdiction and rate. The allocation factors were then applied to the system-wide billing month industrial sales forecast (excluding Schedule 19 Secondary Service) to determine the forecast of billing month industrial sales by rate schedule and jurisdiction. Because only one customer takes service under Schedule 19 Secondary Service, forecast figures were set to match the 2010 normalized energy figures (i.e., no sales growth). No sales growth was assumed based on an historical trend of flat /no growth from 2000 through 2010.

Irrigation Energy Forecast

The irrigation class includes electricity sales to customers taking service under Schedule 24 Secondary Service. Because the irrigation sales forecast was developed on a system-wide basis by billing month, it was necessary to allocate the system-wide irrigation sales forecast to each jurisdiction. In this process, 2010 normalized energy was used to develop allocation factors for each jurisdiction. The allocation factors were then applied to the system-wide billing month irrigation sales forecast to determine the forecast of billing month irrigation sales by jurisdiction.

Energy Forecasts – Special Contracts

The special contract energy forecasts for Simplot Fertilizer, Micron Technology, the INL, and Hoku are each set directly to the values in the long-term sales forecast in the appropriate jurisdiction. For this rate case, however, an adjustment was made regarding the treatment of the Hoku special contract customer. The IRP forecast reflects a ramp-up schedule for Hoku that does not reach full contract levels until early 2011, and maximum capacity in all months of the year until 2013. For ratemaking purposes, 2011 usage has been annualized to reflect loads that would have occurred had Hoku been operating at its full contract level for all twelve months of the year. This adjustment was made to allow the Company to develop rates based on a normalized annualized test year rather than a one-time load pattern that does not reflect typical or expected customer behavior on a long-term basis. More detail on the development of the long-term sales forecast for each special contract customer can be found in *Appendix A –Sales and Load Forecast for the Integrated Resource Plan*.

Expected Oregon Large Load Customer

In *Appendix A – Sales and Load Forecast for the Integrated Resource Plan*, a new large load customer is expected to begin taking service in the Company's Oregon jurisdiction in late 2011. This customer, however, is not included in the load forecast prepared for this rate case filing. As of the rate case filing date, a final signed Electric Service Agreement (ESA) had not been established between Idaho Power and this new large load. While the IRP forecast must incorporate expected large loads into the resource planning process, it is not appropriate to include such loads in the ratemaking process until a contractual agreement for providing electrical service has been finalized.

Customer Forecast Development

System Customer Forecast Development by Class

Once each year a system customer count forecast is prepared for each customer class: residential, commercial, industrial, and irrigation. In the residential customer forecast, the number of residential customers is a function of the number of new service area households as derived from Moody's Analytics forecast of county housing stock and demographic data. Additionally, the number of commercial customers being added each year is a function of the number of new residential customers being added. The industrial and irrigation customer forecasts are based on linear trends of operating area customer counts that are allocated to months and then summed to monthly class totals. The customer forecast process is better described in *Appendix A–Sales and Load Forecast for the Integrated Resource Plan*.

Customer Forecast Development by Jurisdiction and Rate Schedule

To accurately forecast the revenue derived from variable customer charges, it is necessary to develop a more-detailed customer forecast that provides customer counts by jurisdiction and rate schedule. The allocation of system class-level forecasts to jurisdiction and rate schedules are briefly described below for each individual class of customer.

Residential Customer Forecast

The residential class includes customers taking service under Schedules 1, 3, 4, and 5. Since the customer counts in all schedules except Schedule 1 are negligible in comparison to Schedule 1, the forecasts of all schedules except Schedule 1 were set to the most-recent month's actual customer count, December 2010. Jurisdictional split factors were calculated using the 12 months ending December 2010 Schedule 1 actual customer counts by jurisdiction. The resulting factors were applied to the adjusted-system residential class customer forecast (adjusted downward by the forecasted counts of the residential schedules described above) to determine jurisdictional counts for Schedule 1.

Commercial Customer Forecast

The commercial class includes customers taking service under Schedules 7, 9 (Primary, Secondary, and Transmission Service), 40, 41, and 42. Since the customer counts in all schedules except Schedules 7 and 9 Secondary are small in comparison, the forecasts of all schedules except Schedule 7 and 9 Secondary were set to the most-recent month's actual customer count (December

2010). Jurisdictional split factors were calculated using the 12 months ending December 2010 Schedule 7 and 9 Secondary actual customer counts by jurisdiction. The resulting factors were then applied to the adjusted-system commercial class customer forecast (adjusted downward by the forecasted counts of the other commercial schedules described above) to determine jurisdictional counts for Schedule 7 and 9 Secondary. Additionally, the IPUC jurisdiction Schedule 7 and 9 Secondary customer count forecasts were reallocated based on a historical trend analysis of the relationship between Schedule 7 and 9 Secondary customer counts within the IPUC jurisdiction to more accurately reflect future customer counts.

Industrial Customer Forecast

The industrial class includes customers taking service under Schedule 19 (Primary, Secondary, and Transmission Service). Since the customer counts in schedules 19 Secondary and 19 Transmission Service are small in comparison to Schedule 19 Primary, the forecasts of those schedules were set to the most-recent month's actual customer count (December 2010). Jurisdictional split factors were estimated using the 12 months ending December 2010 Schedule 19 Primary actual customer counts by jurisdiction. The resulting factors were then applied to the remaining system industrial class customer forecast (adjusted downward by the forecasted counts of the Schedule 19 Secondary and 19 Transmission Service schedules described above) to determine jurisdictional counts for Schedule 19 Primary.

Irrigation Customer Forecast

The irrigation class includes customers taking service under Schedule 24 Secondary Service. Jurisdictional split factors were estimated using the 12-months ending December 2010 Schedule 24 Secondary actual customer counts by jurisdiction. The resulting factors were then applied to the system irrigation class customer forecast to determine jurisdictional counts for Schedule 24 Secondary.

Summary

This summarizes the development of both the energy sales and customer counts used as inputs to the calculation of normalized revenue.

If you have questions or require additional information, please let me know.

C: Matt Larkin
Greg Said
Catie Miller
Brad Snow
Scott Sparks
Mike Youngblood

Idaho Power/1002
Witness: Matthew T. Larkin

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Matthew T. Larkin
Retail Revenue Forecast Summary

July 29, 2011

IDAHO POWER COMPANY
SUMMARY OF REVENUE FORECAST
TOTAL COMPANY
12 MONTHS ENDING DECEMBER 31, 2011

Tariff Description	January	February	March	April	May	June
1 - Residential Serv.	45,316,626	40,212,509	34,755,596	30,016,470	24,523,062	25,278,822
3 - Residential Master Mete	49,318	42,302	35,992	32,205	24,410	23,808
4 - Residential Energy Wat	8,492	6,544	5,249	4,634	3,873	3,613
5 - Residential TOD	12,853	10,254	8,489	7,006	5,770	5,398
7 - Small General Serv.	1,592,740	1,466,178	1,349,635	1,247,264	1,088,641	1,191,247
9 - Large General Serv.	16,194,371	16,049,186	15,395,860	15,013,564	14,430,758	16,291,839
15 - Dusk/Dawn Lighting	102,571	103,786	102,947	103,671	103,511	103,597
19 - Uniform Rate Cont.	7,655,303	7,489,403	6,954,945	7,357,305	7,005,198	7,312,768
24 - Irrigation & Pump.	121,479	117,218	134,050	951,310	6,824,399	18,455,844
40 - Unmetered Gen. Serv.	89,446	89,277	89,255	89,262	88,787	88,993
41 - Municipal St. Light.	247,972	244,329	237,685	245,432	236,202	239,357
42 - Traffic Control Light.	14,683	13,966	14,090	14,037	13,898	13,787
Total All Rates	71,405,854	65,844,952	59,083,793	55,082,160	54,348,509	69,009,073
Special Contracts						
26 - Micron	1,349,354	1,290,425	1,363,083	1,345,720	1,374,225	1,402,993
29 - J R Simplot	503,405	478,060	512,202	499,270	508,464	385,072
30 - DOE	891,022	760,513	739,979	609,874	522,098	501,716
Total Specials	2,743,781	2,528,998	2,615,264	2,454,864	2,404,787	2,289,781
Total Firm Retail Sales	74,149,635	68,373,950	61,699,057	57,537,024	56,753,296	71,298,854

IDAHO POWER COMPANY
SUMMARY OF REVENUE FORECAST
TOTAL COMPANY
12 MONTHS ENDING DECEMBER 31, 2011

Tariff Description	July	August	September	October	November	December	Total
1 - Residential Serv.	31,471,341	37,782,033	32,245,682	25,327,667	28,532,238	38,803,376	394,265,422
3 - Residential Master Mete	22,948	27,230	26,610	21,651	27,321	38,819	372,614
4 - Residential Energy Wat	3,265	4,109	3,955	2,984	3,255	5,490	55,463
5 - Residential TOD	5,366	7,319	6,908	4,894	5,550	8,051	87,858
7 - Small General Serv.	1,356,184	1,456,201	1,360,045	1,185,614	1,178,007	1,448,446	15,920,202
9 - Large General Serv.	18,521,745	19,112,934	18,327,745	16,131,885	15,385,075	16,163,798	197,018,760
15 - Dusk/Dawn Lighting	103,779	103,796	103,745	103,497	103,205	103,101	1,241,206
19 - Uniform Rate Cont.	9,088,204	9,209,135	9,342,744	7,557,030	7,764,331	7,472,202	94,208,568
24 - Irrigation & Pump.	25,711,632	23,768,524	20,433,198	8,547,823	1,284,553	170,767	106,520,797
40 - Unmetered Gen. Serv.	88,439	87,901	88,503	87,681	87,757	87,787	1,063,088
41 - Municipal St. Light.	239,585	240,261	242,111	242,663	245,831	249,171	2,910,599
42 - Traffic Control Light.	13,799	13,725	12,888	12,383	11,879	12,287	161,422
Total All Rates	86,626,287	91,813,168	82,194,134	59,225,772	54,629,002	64,563,295	813,825,999
Special Contracts							
26 - Micron	1,461,263	1,413,484	1,333,719	1,315,148	1,264,628	1,272,292	16,186,334
29 - J R Simplot	507,870	501,371	489,720	499,147	496,895	510,822	5,892,298
30 - DOE	514,387	511,499	499,527	617,775	694,373	798,621	7,661,384
Total Specials	2,483,520	2,426,354	2,322,966	2,432,070	2,455,896	2,581,735	29,740,016
Total Firm Retail Sales	89,109,807	94,239,522	84,517,100	61,657,842	57,084,898	67,145,030	843,566,015

I D A H O   P O W E R   C O M P A N Y

SUMMARY OF REVENUE FORECAST

STATE OF OREGON

BY MONTH BY RATE

12 MONTHS ENDING DECEMBER 31, 2011

Tariff Description	January	February	March	April	May	June
01 - Residential Serv.	1,907,542	1,719,380	1,476,049	1,225,045	939,520	893,673
07 - Small General Serv.	150,913	138,170	127,232	115,279	104,657	113,269
09 - Large General Serv.	776,055	724,645	663,596	590,486	523,351	568,941
15 - Dusk/Dawn Lighting	9,403	9,387	9,388	9,378	9,380	9,368
19 - Uniform Rate Cont.	830,327	760,485	715,029	1,052,234	856,985	856,569
24 - Irrigation Service	6,582	5,816	5,644	7,457	205,188	670,744
40 - Unmetered Gen. Serv.	81	81	81	81	81	81
41 - Municipal St. Light.	10,412	10,379	10,169	10,352	10,323	10,270
42 - Traffic Control Light.	103	102	102	103	103	103
Total Oregon Firm Sales	3,691,418	3,368,445	3,007,290	3,010,415	2,649,588	3,123,018

IDAHO POWER COMPANY
SUMMARY OF REVENUE FORECAST
STATE OF OREGON
BY MONTH BY RATE
12 MONTHS ENDING DECEMBER 31, 2011

Tariff Description	July	August	September	October	November	December	Total
01 - Residential Serv.	1,075,926	1,279,463	1,115,178	949,786	1,145,562	1,628,808	15,355,932
07 - Small General Serv.	127,340	148,408	130,247	119,154	127,057	157,674	1,559,400
09 - Large General Serv.	624,169	668,242	654,483	650,543	705,492	779,011	7,929,014
15 - Dusk/Dawn Lighting	9,389	9,343	9,365	9,447	9,319	9,295	112,462
19 - Uniform Rate Cont.	1,189,534	1,100,513	1,213,486	1,004,019	871,879	885,398	11,336,458
24 - Irrigation Service	761,495	829,483	724,240	195,883	30,759	10,980	3,454,271
40 - Unmetered Gen. Serv.	81	81	81	81	81	81	972
41 - Municipal St. Light.	10,283	10,279	10,303	10,333	10,356	10,392	123,851
42 - Traffic Control Light.	103	103	102	102	103	102	1,231
Total Oregon Firm Sales	3,798,320	4,045,915	3,857,485	2,939,348	2,900,608	3,481,741	39,873,591

IDAHO POWER COMPANY
SUMMARY OF REVENUE FORECAST
IDAHO JURISDICTION
BY MONTH BY RATE
12 MONTHS ENDING DECEMBER 31, 2011

Tariff Description	January	February	March	April	May	June
1 - Residential Serv.	43,409,084	38,493,129	33,279,547	28,791,425	23,583,542	24,385,149
3 - Residential Master Mete	49,318	42,302	35,992	32,205	24,410	23,808
4 - Residential Energy Wat	8,492	6,544	5,249	4,634	3,873	3,613
5 - Residential TOD	12,853	10,254	8,489	7,006	5,770	5,398
7 - Small General Serv.	1,441,827	1,328,008	1,222,403	1,131,985	983,984	1,077,978
9 - Large General Serv.	15,418,316	15,324,541	14,732,264	14,423,078	13,907,407	15,722,898
15 - Dusk/Dawn Lighting	93,168	94,399	93,559	94,293	94,131	94,229
19 - Uniform Rate Cont.	6,824,976	6,728,918	6,239,916	6,305,071	6,148,213	6,456,199
24 - Irrigation & Pump.	114,897	111,402	128,406	943,853	6,619,211	17,785,100
40 - Unmetered Gen. Serv.	89,365	89,196	89,174	89,181	88,706	88,912
41 - Municipal St. Light.	237,560	233,950	227,516	235,080	225,879	229,087
42 - Traffic Control Light.	14,580	13,864	13,988	13,934	13,795	13,684
Total Idaho Rates	67,714,436	62,476,507	56,076,503	52,071,745	51,698,921	65,886,055
Special Contracts						
26 - Micron	1,349,354	1,290,425	1,363,083	1,345,720	1,374,225	1,402,993
29 - J R Simplot	503,405	478,060	512,202	499,270	508,464	385,072
30 - DOE	891,022	760,513	739,979	609,874	522,098	501,716
Total Specials	2,743,781	2,528,998	2,615,264	2,454,864	2,404,787	2,289,781
Total Idaho Firm Sales	70,458,217	65,005,505	58,691,767	54,526,609	54,103,708	68,175,836

IDAHO POWER COMPANY
SUMMARY OF REVENUE FORECAST
IDAHO JURISDICTION
BY MONTH BY RATE
12 MONTHS ENDING DECEMBER 31, 2011

Tariff Description	July	August	September	October	November	December	Total
1 - Residential Serv.	30,395,415	36,502,570	31,130,504	24,377,881	27,386,676	37,174,568	378,909,490
3 - Residential Master Mete	22,948	27,230	26,610	21,651	27,321	38,819	372,614
4 - Residential Energy Wat	3,265	4,109	3,955	2,984	3,255	5,490	55,463
5 - Residential TOD	5,366	7,319	6,908	4,894	5,550	8,051	87,858
7 - Small General Serv.	1,228,844	1,307,793	1,229,798	1,066,460	1,050,950	1,290,772	14,360,802
9 - Large General Serv.	17,897,576	18,444,692	17,673,262	15,481,342	14,679,583	15,384,787	189,089,746
15 - Dusk/Dawn Lighting	94,390	94,453	94,380	94,050	93,886	93,806	1,128,744
19 - Uniform Rate Cont.	7,898,670	8,108,622	8,129,258	6,553,011	6,892,452	6,586,804	82,872,110
24 - Irrigation & Pump.	24,950,137	22,939,041	19,708,958	8,351,940	1,253,794	159,787	103,066,526
40 - Unmetered Gen. Serv.	88,358	87,820	88,422	87,600	87,676	87,706	1,062,116
41 - Municipal St. Light.	229,302	229,982	231,808	232,330	235,475	238,779	2,786,748
42 - Traffic Control Light.	13,696	13,622	12,786	12,281	11,776	12,185	160,191
Total Idaho Rates	82,827,967	87,767,253	78,336,649	56,286,424	51,728,394	61,081,554	773,952,408
Special Contracts							
26 - Micron	1,461,263	1,413,484	1,333,719	1,315,148	1,264,628	1,272,292	16,186,334
29 - J R Simplot	507,870	501,371	489,720	499,147	496,895	510,822	5,892,298
30 - DOE	514,387	511,499	499,527	617,775	694,373	798,621	7,661,384
Total Specials	2,483,520	2,426,354	2,322,966	2,432,070	2,455,896	2,581,735	29,740,016
Total Idaho Firm Sales	85,311,487	90,193,607	80,659,615	58,718,494	54,184,290	63,663,289	803,692,424

STATE OF OREGON

Tariff Description	January	February	March	April	May	June
9S	688,016	642,194	589,112	508,310	448,608	494,413
9P	72,228	71,527	63,847	66,241	61,827	63,864
9T	15,811	10,924	10,637	15,935	12,916	10,664
Total Rate 9	776,055	724,645	663,596	590,486	523,351	568,941
19S	0	0	0	0	0	0
19P	658,821	719,531	639,752	661,938	636,101	729,631
19T	171,506	40,954	75,277	390,296	220,884	126,938
Total Rate 19	830,327	760,485	715,029	1,052,234	856,985	856,569
24S	6,582	5,816	5,644	7,457	205,188	670,744
24T	0	0	0	0	0	0
Total 24	6,582	5,816	5,644	7,457	205,188	670,744

STATE OF OREGON

Tariff Description	July	August	September	October	November	December	Total
9S	543,113	582,757	567,078	577,244	634,183	700,887	6,975,915
9P	67,844	72,468	73,854	60,709	59,711	63,982	798,102
9T	13,212	13,017	13,551	12,590	11,598	14,142	154,997
Total Rate 9	624,169	668,242	654,483	650,543	705,492	779,011	7,929,014
19S	0	0	0	0	0	0	0
19P	770,682	713,167	761,735	626,043	684,463	611,201	8,213,065
19T	418,852	387,346	451,751	377,976	187,416	274,197	3,123,393
Total Rate 19	1,189,534	1,100,513	1,213,486	1,004,019	871,879	885,398	11,336,458
24S	761,495	829,483	724,240	195,883	30,759	10,980	3,454,271
24T	0	0	0	0	0	0	0
Total 24	761,495	829,483	724,240	195,883	30,759	10,980	3,454,271

IDAHO JURISDICTION

Tariff Description	January	February	March	April	May	June
9S	13,989,541	13,876,547	13,389,460	12,986,448	12,507,024	14,267,675
9P	1,419,959	1,439,985	1,334,967	1,427,609	1,388,796	1,444,591
9T	8,816	8,009	7,837	9,021	11,587	10,632
Total Rate 9	15,418,316	15,324,541	14,732,264	14,423,078	13,907,407	15,722,898
19S	30,287	30,297	26,772	27,915	26,159	26,438
19P	6,665,436	6,584,273	6,099,583	6,152,056	6,025,041	6,282,271
19T	129,253	114,348	113,561	125,100	97,013	147,490
Total Rate 19	6,824,976	6,728,918	6,239,916	6,305,071	6,148,213	6,456,199
24S	114,897	111,402	128,406	943,853	6,619,211	17,785,100
24T	0	0	0	0	0	0
Total 24	114,897	111,402	128,406	943,853	6,619,211	17,785,100

IDAHO JURISDICTION

Tariff Description	July	August	September	October	November	December	Total
9S	16,205,655	16,616,989	15,776,038	13,918,926	13,171,838	13,890,656	170,596,797
9P	1,678,337	1,816,511	1,887,627	1,554,656	1,499,747	1,485,033	18,377,818
9T	13,584	11,192	9,597	7,760	7,998	9,098	115,131
Total Rate 9	17,897,576	18,444,692	17,673,262	15,481,342	14,679,583	15,384,787	189,089,746
19S	26,408	27,318	27,093	23,223	29,045	26,516	327,471
19P	7,692,934	7,914,109	7,918,654	6,394,518	6,731,974	6,433,232	80,894,081
19T	179,328	167,195	183,511	135,270	131,433	127,056	1,650,558
Total Rate 19	7,898,670	8,108,622	8,129,258	6,553,011	6,892,452	6,586,804	82,872,110
24S	24,950,137	22,939,041	19,708,958	8,351,940	1,253,794	159,787	103,066,526
24T	0	0	0	0	0	0	0
Total 24	24,950,137	22,939,041	19,708,958	8,351,940	1,253,794	159,787	103,066,526

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Matthew T. Larkin
Retail Revenue Forecast Derivation

July 29, 2011

2011 Retail Revenue Forecast Derivation

Rate	State		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	Rates 6/1/2011
IDAHO																
Rate 01	I	**Bills**	396398.9	395863.4	395993	396292.4	396310.7	396786.7	397034.3	397484.8	397840.3	398505.8	398944.5	399731	4767185.8	4.000000
		Min Bills	2236.2	3026.0	3229.4	3184.0	3568.6	3519.2	3353.9	3854.5	3436.5	3299.3	3006.5	2429.4	38143.5	2.000000
		S 0-800	1,098	9,134	10,311	6,913	2,252	88,603,613	258,132,926	274,541,633	187,085,330	3,868,692	6,320	(51,740)	812,216,482	0.071026
		S 801-2000	780	5,068	5,391	3,256	776	26,246,850	99,923,713	144,839,162	73,525,643	1,192,559	2,342	(32,652)	345,712,888	0.086530
		S Over 2000	495	1,944	1,790	828	120	3,458,716	15,107,564	27,653,983	11,535,508	157,537	388	(15,355)	57,903,518	0.103836
		N 0-800	266,877,892	294,935,077	265,303,309	244,876,992	228,689,603	151,769,231	2,520,365	8,063	86,486,816	242,237,248	261,150,494	258,105,156	2,302,960,245	0.066259
		N 801-2000	189,521,297	163,637,155	138,694,325	115,313,390	78,822,168	44,958,259	975,638	4,254	33,989,831	74,671,831	96,769,151	162,886,941	1,100,244,240	0.073621
		N Over 2000	120,278,399	62,756,607	46,044,094	29,343,004	12,227,584	5,924,439	147,508	812	5,332,697	9,864,144	16,021,128	76,600,964	384,541,379	0.084662
		Total kWh	576,679,960	521,344,984	450,059,219	389,544,384	319,742,503	320,961,109	376,807,715	447,047,907	397,955,825	331,992,011	373,949,822	497,493,313	5,003,578,752	
		Rev	43,409,084	38,493,129	33,279,547	28,791,425	23,583,542	24,385,149	30,395,415	36,502,570	31,130,504	24,377,881	27,386,676	37,174,568	378,909,490	
Rate 03	I	**Bills**	22	22	22	22	22	22	22	22	22	22	22	22	264	4.000000
		Total kWh	685,712	587,982	500,091	447,345	338,779	330,386	318,414	378,053	369,414	300,340	379,320	539,475	5,175,311	0.071794
		Rev	49,318	42,302	35,992	32,205	24,410	23,808	22,948	27,230	26,610	21,651	27,321	38,819	372,614	
Rate 04	I	**Bills**	42	43.2	42	42	42	43	43.4	42	42.4	41.7	42	43.9	509.6	4.000000
		Min Bills	0.0	0.3	0.0	0.0	0.0	0.0	0.1	0.0	0.2	0.0	0.0	0.0	0.6	2.000000
		S EW	0	0	0	0	0	0	180	213	213	0	0	0	606	0.200000
		S Reg kWh	0	0	0	0	0	3,082	41,346	53,132	50,116	614	0	0	148,289	0.073366
		N 0-800	35,695	40,684	35,345	32,943	32,882	31,552	298	0	861	29,413	31,286	32,327	303,287	0.066259
		N 801-2000	36,555	36,076	29,776	25,383	19,304	14,412	32	0	121	10,194	13,200	29,870	214,924	0.073621
		N Over 2000	38,599	12,031	6,459	4,901	1,239	750	0	0	0	854	502	11,497	76,833	0.084662
		Total kWh	110,849	88,790	71,581	63,228	53,426	49,796	41,856	53,345	51,311	41,075	44,988	73,694	743,939	
		Rev	8,492	6,544	5,249	4,634	3,873	3,613	3,265	4,109	3,955	2,984	3,255	5,490	55,463	

2011 Retail Revenue Forecast Derivation

Rate 05	I	**Bills**	72.1	73.9	73.7	74.8	73.6	73.1	73	73	74	73	73	74.8	882	4.000000
		Min Bills	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	2.000000
		S On Peak	0	0	0	0	0	632	18,008	26,678	25,912	859	0	0	72,090	0.106215
		S Mid Peak	0	0	0	0	0	536	12,791	14,726	14,249	613	0	0	42,914	0.078146
		S Off Peak	0	0	0	0	0	646	36,265	51,956	46,896	1,173	0	0	136,937	0.058565
		N 0-800	60,201	68,884	62,024	57,119	54,373	55,414	573	0	0	52,550	57,573	54,175	522,886	0.066259
		N 801-2000	62,338	56,353	44,551	37,101	24,939	17,478	0	0	0	12,397	19,187	45,519	319,863	0.073621
		N Over 2000	47,085	14,710	9,510	2,232	438	0	0	0	0	0	358	9,584	83,918	0.084662
		Total kWh	169,624	139,947	116,085	96,453	79,751	74,705	67,637	93,361	87,057	67,592	77,118	109,278	1,178,608	
		Rev	12,853	10,254	8,489	7,006	5,770	5,398	5,366	7,319	6,908	4,894	5,550	8,051	87,858	
Rate 07	I	**Bills**	28,513	28,339	28,621	28,334	28,280	28,717	28,165	28,300	28,224	28,247	28,212	28,256	340208.4	4.000000
		Min Bills	99.4	91.0	96.1	89.6	103.8	84.4	68.7	95.2	79.7	108.4	103.4	80.6	1100.3	2.000000
		S 0-300	(251)	902	12,825	(143)	1	2,133,884	5,491,953	5,469,219	3,685,405	77,508	12,340	(2,802)	16,880,841	0.083076
		S Over	(431)	1,233	16,397	(172)	1	2,062,525	6,577,439	7,500,094	4,619,509	86,314	13,334	(4,139)	20,872,104	0.098910
		N 0-300	5,675,405	5,980,911	5,656,873	5,412,882	5,179,551	3,463,321	48,989	(8,797)	1,831,063	5,187,805	5,257,151	5,537,420	49,222,574	0.083075
		N Over	9,749,965	8,169,922	7,232,531	6,477,796	5,014,900	3,347,504	58,672	(12,064)	2,295,165	5,777,212	5,680,538	8,179,011	61,971,152	0.087811
		kWh Total	15,424,688	14,152,968	12,918,626	11,890,363	10,194,453	11,007,233	12,177,054	12,948,452	12,431,142	11,128,839	10,963,362	13,709,490	148,946,670	
		Rev	1,441,827	1,328,008	1,222,403	1,131,985	983,984	1,077,978	1,228,844	1,307,793	1,229,798	1,066,460	1,050,950	1,290,772	14,360,802	
Rate 09S	I	**Bills**	29917.1	29941.9	30090	30086.2	30305.1	30077.7	30341.1	30526.8	30576.1	30819.6	30825.1	31064.7	364571.4	14.430000
		Min Bills	41.6	66.2	59.3	55.1	63.3	49.7	37.6	32.4	38.1	46.7	57.3	46.5	593.9	5.000000
		BLC 0-20	437,812	445,315	446,737	447,968	442,887	460,803	462,389	459,083	457,930	460,135	450,843	454,753	5,426,656	0.000000
		BLC Over 20	638,162	645,827	645,415	645,069	640,752	662,615	666,385	657,508	651,509	651,225	637,146	639,553	7,781,165	0.780000
		BLC Total	1,075,974	1,091,142	1,092,152	1,093,037	1,083,639	1,123,418	1,128,774	1,116,591	1,109,440	1,111,359	1,087,989	1,094,306	13,207,821	
		kW 0-20	367,683	376,771	372,716	380,510	388,073	407,611	403,187	398,975	395,619	398,649	379,954	377,783	4,647,531	0.000000
		S kW Over 20	99	0	0	0	0	187,377	483,240	497,464	323,412	9,745	306	211	1,501,856	4.610000
		N kW Over 20	428,964	422,018	418,630	422,083	440,749	277,061	6,596	123	185,301	487,037	440,747	436,570	3,965,879	3.680000
		kW Total	796,746	798,789	791,346	802,593	828,823	872,049	893,023	896,562	904,332	895,431	821,008	814,564	10,115,266	
		S 0-2000	(308)	0	(5,270)	0	(409)	19,968,119	48,878,725	48,965,193	31,869,175	937,005	50,396	27,330	150,689,955	0.090122
		S Over	(1,415)	0	(21,387)	0	(1,569)	80,004,335	218,439,589	231,763,833	145,257,369	4,147,631	208,301	121,606	679,918,294	0.038639
		N 0-2000	48,060,674	52,277,168	49,542,428	48,269,776	46,803,861	29,943,255	642,072	7,160	17,553,926	46,720,600	47,536,765	48,463,184	435,820,869	0.080407
		N Over	220,998,312	208,447,390	201,042,413	191,921,481	179,445,254	119,970,752	2,869,428	33,892	80,009,509	206,807,671	196,481,241	215,640,054	1,823,667,397	0.034464
		kWh Total	269,057,263	260,724,558	250,558,184	240,191,257	226,247,137	249,886,461	270,829,814	280,770,078	274,689,979	258,612,906	244,276,703	264,252,174	3,090,096,514	
		Rev	13,989,541	13,876,547	13,389,460	12,986,448	12,507,024	14,267,675	16,205,655	16,616,989	15,776,038	13,918,926	13,171,838	13,890,656	170,596,797	

2011 Retail Revenue Forecast Derivation

Rate 09P	I	**Bills**	179.3	177.9	178.9	175	179.3	180.9	180	180.2	172.5	177.5	181.5	182.7	2145.7	247.270000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.2	10.000000
		BLC	95,115	98,631	96,617	101,321	99,552	100,212	95,087	100,084	102,784	103,626	104,753	105,977	1,203,758	1.120000
		S kW	0	0	0	0	0	0	79,920	85,533	91,715	0	0	0	257,168	4.240000
		N kW	73,877	76,692	74,129	78,134	79,848	83,408	0	0	7	89,667	84,255	83,101	723,117	3.910000
		Total kW	73,877	76,692	74,129	78,134	79,848	83,408	79,920	85,533	91,722	89,667	84,255	83,101	980,284	
		On-peak kW	0	0	0	0	0	0	73,950	79,427	86,011	0	0	0	239,388	0.790000
		S On-peak kWh	0	0	0	0	0	0	9,265,938	9,572,062	10,425,155	0	0	0	29,263,155	0.037953
		S Mid-peak kWh	0	0	0	0	0	0	14,120,459	15,386,712	16,143,069	0	0	0	45,650,239	0.034511
		S Off-peak kWh	0	0	0	0	0	0	9,024,216	10,546,094	9,926,688	0	0	0	29,496,998	0.032254
		N Mid-peak kWh	20,336,089	19,881,848	19,004,798	20,850,228	19,924,175	19,635,767	0	0	997	22,453,564	21,402,343	20,696,984	184,186,793	0.030127
		N Off-peak kWh	12,722,711	13,384,216	11,080,181	11,671,491	11,093,479	12,804,301	0	0	741	12,725,374	12,575,481	12,900,237	110,958,212	0.028891
		Total kWh	33,058,800	33,266,064	30,084,979	32,521,719	31,017,654	32,440,068	32,410,613	35,504,868	36,496,649	35,178,938	33,977,824	33,597,221	399,555,397	
		Rev	1,419,959	1,439,985	1,334,967	1,427,609	1,388,796	1,444,591	1,678,337	1,816,511	1,887,627	1,554,656	1,499,747	1,485,033	18,377,818	
Rate 09T	I	**Bills**	2	2	2	2	2	2	2	2	2	2	2	2	24	247.270000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	869	872	928	876	852	702	877	853	772	719	733	809	9,861	0.580000
		S kW	0	0	0	0	0	0	834	643	522	0	0	0	1,999	4.060000
		N kW	484	394	395	493	815	681	0	0	0	491	469	579	4,800	3.760000
		Total kW	484	394	395	493	815	681	834	643	522	491	469	579	6,799	
		On-peak kW	0	0	0	0	0	0	718	552	435	0	0	0	1,704	0.790000
		S On-peak kWh	0	0	0	0	0	0	59,385	49,307	45,487	0	0	0	154,179	0.037318
		S Mid-peak kWh	0	0	0	0	0	0	108,992	85,168	76,593	0	0	0	270,753	0.034016
		S Off-peak kWh	0	0	0	0	0	0	84,882	76,001	59,360	0	0	0	220,243	0.031841
		N Mid-peak kWh	117,421	102,569	103,809	122,053	143,766	140,249	0	0	0	98,621	104,141	115,965	1,048,594	0.029771
		N Off-peak kWh	87,352	86,388	77,788	88,380	113,586	104,545	0	0	0	72,171	77,371	87,390	794,971	0.028645
		Total kWh	204,773	188,957	181,597	210,433	257,352	244,794	253,259	210,476	181,440	170,792	181,512	203,355	2,488,740	
		Rev	8,816	8,009	7,837	9,021	11,587	10,632	13,584	11,192	9,597	7,760	7,998	9,098	115,131	
Rate 19S	I	**Bills**	1	1	1	1	1	1	1	1	1	1	1	1	12	14.380000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.000000
		BLC	1,462	1,479	1,403	1,398	1,362	1,364	1,218	1,152	1,186	1,291	1,380	1,332	16,027	0.780000
		S kW	0	0	0	0	0	0	1,038	1,060	1,034	0	0	0	3,132	3.920000
		N kW	1,345	1,359	1,268	1,246	1,242	1,304	0	0	0	1,108	1,334	1,216	11,422	3.670000
		Total kW	1,345	1,359	1,268	1,246	1,242	1,304	1,038	1,060	1,034	1,108	1,334	1,216	14,555	
		On-peak kW	0	0	0	0	0	0	915	991	916	0	0	0	2,822	0.790000
		S On-peak kWh	0	0	0	0	0	0	128,411	125,160	134,720	0	0	0	388,291	0.051863
		S Mid-peak kWh	0	0	0	0	0	0	219,266	230,781	228,701	0	0	0	678,748	0.039741
		S Off-peak kWh	0	0	0	0	0	0	152,764	167,962	153,324	0	0	0	474,050	0.034555
		N Mid-peak kWh	412,900	393,271	360,909	389,632	357,606	339,320	0	0	0	308,603	396,446	356,975	3,315,662	0.036612
		N Off-peak kWh	285,358	306,288	244,991	250,512	233,525	256,169	0	0	0	214,883	268,517	249,309	2,309,552	0.031817
		Total kWh	698,258	699,559	605,900	640,144	591,131	595,489	500,441	523,903	516,745	523,486	664,963	606,284	7,166,303	
		Rev	30,287	30,297	26,772	27,915	26,159	26,438	26,408	27,318	27,093	23,223	29,045	26,516	327,471	

2011 Retail Revenue Forecast Derivation

Rate 19P	I	**Bills**	110	110	110	111	109	108	110	110	111	110	110	107	1316	247.270000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	10.000000
		BLC	397,352	392,524	392,884	384,628	396,578	401,541	399,910	396,241	398,347	393,907	395,111	394,249	4,743,270	1.120000
		S kW	(254)	0	0	0	0	0	344,363	347,933	359,449	0	0	0	1,051,491	4.240000
		N kW	351,514	334,359	330,598	314,988	323,305	333,853	0	0	0	345,605	350,093	340,635	3,024,950	3.910000
		Total kW	351,260	334,359	330,598	314,988	323,305	333,853	344,363	347,933	359,449	345,605	350,093	340,635	4,076,441	
		On-peak kW	(248)	0	0	0	0	0	320,572	332,993	343,449	0	0	0	996,766	0.790000
		S On-peak kWh	(38,262)	0	0	0	0	0	43,643,994	43,248,421	44,103,193	0	0	0	130,957,346	0.041819
		S Mid-peak kWh	(67,278)	0	0	0	0	0	70,685,248	73,313,013	73,611,199	0	0	0	217,542,182	0.031856
		S Off-peak kWh	(57,774)	0	0	0	0	0	51,552,363	56,361,184	52,735,832	0	0	0	160,591,605	0.027692
		N Mid-peak kWh	101,220,404	98,218,668	92,563,219	96,981,979	93,472,198	92,292,292	0	0	0	97,807,820	102,868,905	96,418,243	871,843,728	0.029490
		N Off-peak kWh	71,770,368	74,626,034	62,786,174	62,481,889	59,794,268	69,366,764	0	0	0	65,923,414	72,525,982	69,803,029	609,077,921	0.025643
		Total kWh	172,827,458	172,844,702	155,349,393	159,463,868	153,266,466	161,659,056	165,881,605	172,922,618	170,450,223	163,731,234	175,394,887	166,221,272	1,990,012,782	
		Rev	6,665,436	6,584,273	6,099,583	6,152,056	6,025,041	6,282,271	7,692,934	7,914,109	7,918,654	6,394,518	6,731,974	6,433,232	80,894,081	
Rate 19T	I	**Bills**	3	3	3	3	3	3	3	3	3	3	3	3	36	247.270000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	7,087	7,471	7,653	7,407	6,108	8,062	8,041	7,598	8,252	7,674	7,154	7,136	89,644	0.580000
		S kW	0	0	0	0	0	0	7,502	6,846	7,431	0	0	0	21,779	4.060000
		N kW	6,389	5,718	6,099	6,226	5,295	7,346	0	0	0	6,737	6,478	6,475	56,762	3.760000
		Total kW	6,389	5,718	6,099	6,226	5,295	7,346	7,502	6,846	7,431	6,737	6,478	6,475	78,541	
		On-peak kW	0	0	0	0	0	0	7,336	6,533	7,251	0	0	0	21,120	0.790000
		S On-peak kWh	0	0	0	0	0	0	1,106,916	976,255	1,125,683	0	0	0	3,208,853	0.041479
		S Mid-peak kWh	0	0	0	0	0	0	1,679,341	1,596,686	1,788,971	0	0	0	5,064,999	0.031746
		S Off-peak kWh	0	0	0	0	0	0	1,392,578	1,373,265	1,398,313	0	0	0	4,164,156	0.027605
		N Mid-peak kWh	2,121,585	1,755,286	1,812,929	2,105,670	1,605,633	2,365,135	0	0	0	2,230,857	2,175,430	2,046,838	18,219,363	0.029341
		N Off-peak kWh	1,494,550	1,421,722	1,264,351	1,366,836	1,007,761	1,766,133	0	0	0	1,540,031	1,503,447	1,480,509	12,845,340	0.025512
		Total kWh	3,616,135	3,177,008	3,077,280	3,472,506	2,613,394	4,131,268	4,178,835	3,946,206	4,312,967	3,770,888	3,678,877	3,527,347	43,502,711	
		Rev	129,253	114,348	113,561	125,100	97,013	147,490	179,328	167,195	183,511	135,270	131,433	127,056	1,650,558	
Rate 24	I	**In Bills**	0	0	0	0	0	16577.4	16939.3	16993.5	16928.9	0	0	0	67439.1	18.180000
	I	**Out-Bills**	16030.6	16391.7	16304.6	16264	16432.8	0	0	0	0	17150	16776.7	16499.6	131850	3.460000
		Min Bills	27.1	13.8	38.1	107.0	100.5	186.5	6.5	5.5	13.0	45.5	57.2	47.7	648.5	1.500000
		In-kW	0	0	0	0	0	920,862	1,005,170	895,736	866,817	0	0	0	3,688,584	5.650000
		Out-kW	7,004	6,432	11,055	136,200	688,936	0	0	0	0	708,149	212,304	23,935	1,794,016	0.000000
		Total kW	7,004	6,432	11,055	136,200	688,936	920,862	1,005,170	895,736	866,817	708,149	212,304	23,935	5,482,600	
		In <164 kWh per	0	0	0	0	0	167,087,354	161,873,653	138,186,998	130,360,967	0	0	0	597,508,971	0.046851
		In >164 kWh per	0	0	0	0	0	97,886,460	250,170,822	243,926,215	184,590,864	0	0	0	776,574,362	0.045485
		Out-kWh	1,053,914	970,087	1,276,530	15,747,786	116,450,228	0	0	0	0	147,155,954	21,217,722	1,821,180	305,693,401	0.056352
		Total kWh	1,053,914	970,087	1,276,530	15,747,786	116,450,228	264,973,814	412,044,475	382,113,213	314,951,831	147,155,954	21,217,722	1,821,180	1,679,776,734	
		Rev	114,897	111,402	128,406	943,853	6,619,211	17,785,100	24,950,137	22,939,041	19,708,958	8,351,940	1,253,794	159,787	103,066,526	

2011 Retail Revenue Forecast Derivation

Rate 40	I	**In Bills**	1984	1984	1984	1984	1984	1984	1984	1984	1984	1984	1984	1984	23808	0.000000
		Min Bills	82.6	82.6	82.5	86.2	84.8	83.5	73.9	74.7	72.4	71.6	73.5	74.0	942.3	1.500000
		kWh	1,346,223	1,343,670	1,343,340	1,343,371	1,336,227	1,339,368	1,331,230	1,323,091	1,332,228	1,319,848	1,320,956	1,321,389	16,000,941	0.066290
		Rev	89,365	89,196	89,174	89,181	88,706	88,912	88,358	87,820	88,422	87,600	87,676	87,706	1,062,116	0.000000
Rate 42	I	**Bills**	358	358	358	358	358	358	358	358	358	358	358	358	4296	0.000000
		kWh	316,475	300,930	303,616	302,453	299,431	297,029	297,295	295,671	277,537	266,578	255,618	264,480	3,477,113	0.046070
		Rev	14,580	13,864	13,988	13,934	13,795	13,684	13,696	13,622	12,786	12,281	11,776	12,185	160,191	0.000000
Rate 15	kWh/lamp	1csa	324,574	324,969	321,982	325,765	325,713	325,059	324,931	324,287	323,766	324,301	324,173	325,830	3,895,350	
kWh		2csa	50,523	53,876	52,270	52,116	51,996	51,847	51,943	52,101	51,801	51,607	51,659	49,470	621,210	
		2csf	54,867	57,785	57,771	58,044	57,881	57,886	57,795	58,210	57,783	57,558	57,699	57,813	691,092	
		4chf	10,076	10,387	10,179	10,076	10,076	10,384	10,403	10,386	10,382	10,398	9,804	9,146	121,698	
		4csa	16,753	17,304	17,101	17,115	17,115	16,872	16,596	16,486	16,590	16,644	16,644	16,831	202,052	
		4csf	70,733	70,014	70,190	70,013	69,087	69,713	71,754	71,828	72,279	70,490	70,101	70,410	846,614	
		1khf	13,757	14,483	14,120	14,674	14,844	16,121	15,542	16,217	17,088	15,930	15,736	15,567	184,079	
		Total kWh	541,284	548,818	543,614	547,803	546,712	547,882	548,965	549,515	549,689	546,928	545,817	545,068	6,562,095	
Lamps	39	1csa	8,322	8,333	8,256	8,353	8,352	8,335	8,332	8,315	8,302	8,315	8,312	8,355	99,882	7.200000
	74	2csa	683	728	706	704	703	701	702	704	700	697	698	669	8,395	11.650000
	74	2csf	741	781	781	784	782	782	781	787	781	778	780	781	9,339	14.170000
	155	4chf	65	67	66	65	65	67	67	67	67	67	63	59	785	23.680000
	157	4csa	107	110	109	109	109	107	106	105	106	106	106	107	1,287	18.670000
	157	4csf	451	446	447	446	440	444	457	458	460	449	447	448	5,393	21.180000
	362	1khf	38	40	39	41	41	45	43	45	47	44	43	43	509	43.200000
		Fac Chg	7,025	7,234	7,034	7,118	7,106	7,100	7,243	7,230	7,217	7,043	7,050	7,051	85,451	
		Min Bill	20.7	12.8	24.6	16.3	20.3	12.3	17.4	13.4	15.1	20.6	19.8	16.0	209.5	3.000000
		kWh	541,284	548,818	543,614	547,803	546,712	547,882	548,965	549,515	549,689	546,928	545,817	545,068	6,562,095	
		Rev	93,168	94,399	93,559	94,293	94,131	94,229	94,390	94,453	94,380	94,050	93,886	93,806	1,128,744	

2011 Retail Revenue Forecast Derivation

Rate 41A		29	70 S	36	36	36	37	37	37	37	39	39	39	39	39	452	8.710000
		39	100 S	14,746	14,732	14,525	14,731	14,731	14,721	14,707	14,741	14,814	14,758	14,760	14,843	176,809	7.830000
		74	200 S	1,863	1,855	1,733	1,846	1,846	1,837	1,836	1,828	1,828	1,810	1,810	1,826	21,917	9.170000
		100	250 S	95	95	94	96	96	96	98	101	102	101	101	102	1,179	10.370000
		157	400 S	70	70	65	66	67	67	67	67	68	67	67	71	814	13.060000
	I		**Bills**	314	314	314	314	314	314	314	314	314	314	314	314	3768	
			Variable Usage (	5,190	5,190	5,190	5,190	5,190	5,190	5,190	5,190	5,190	5,190	5,190	5,190	62280	0.066290
			kWh	2,005,970	1,947,389	1,876,272	1,943,711	1,833,807	1,866,017	1,870,013	1,877,652	1,900,532	1,915,546	1,968,024	2,013,916	23,018,849	
			Rev 41A	135,109	134,924	132,100	134,802	134,816	134,655	134,551	134,787	135,383	134,768	134,778	135,636	1,616,309	
			Rev All 41	237,560	233,950	227,516	235,080	225,879	229,087	229,302	229,982	231,808	232,330	235,475	238,779	2,786,748	
Rate 41B		66	2500 I	0	0	0	0	0	0	0	0	0	0	0	0	0	
		68	175 M	8	8	8	8	8	8	8	8	8	8	8	8	96	6.430000
		155	400 M	7	7	7	7	7	5	5	5	5	5	5	5	70	10.160000
		388	1000 M	0	0	0	0	0	0	0	0	0	0	0	0	0	
		29	70 S	5	5	5	5	5	5	5	5	5	5	5	5	60	3.740000
		39	100 S	10,767	10,768	10,632	11,433	10,154	10,787	10,779	10,798	10,859	10,810	10,824	10,850	129,462	4.240000
		74	200 S	450	450	445	448	408	429	429	430	433	432	433	433	5,218	5.880000
		100	250 S	3,540	3,519	3,142	3,572	3,435	3,502	3,515	3,552	3,504	3,557	3,553	3,557	41,947	6.990000
		157	400 S	977	958	947	999	928	963	988	999	1,004	999	1,002	1,004	11,769	9.720000
			Variable Usage (	344	344	344	344	344	344	344	344	344	344	344	344	4,128	0.066290
			Rev 41B	82,696	82,379	79,025	85,962	78,649	82,245	82,535	82,997	82,984	83,088	83,157	83,319	989,036	
Rate 41BM		39	100 S	0	0	0	0	0	0	0	0	0	0	0	0	0	2.230000
		74	200 S	0	0	0	0	0	0	0	0	0	0	0	0	0	2.310000
		100	250 S	16	16	16	16	16	16	16	16	16	16	16	16	192	2.230000
		157	400 S	9	9	9	9	9	25	34	25	25	25	25	25	230	2.290000
			Bills	9	9	6	6	6	10	10	10	10	12	12	12	112	8.570000
			kWh	3,024	3,024	2,982	3,022	3,022	5,538	6,948	5,542	5,571	5,546	5,546	5,553	55,318	0.059385
			Rev 41BM	313	313	284	287	287	508	612	508	510	525	526	526	5,199	
Rate 41M	I		**Bills**	155	155	159	162	163	161	163	164	169	170	171	171	1963	8.570000
			kWh	305,014	252,688	248,292	212,856	180,693	173,424	171,885	173,182	193,366	210,359	261,831	300,292	2,683,882	0.059385
			Rev 41M	19,442	16,334	16,107	14,029	12,127	11,679	11,604	11,690	12,931	13,949	17,014	19,298	176,204	

2011 Retail Revenue Forecast Derivation

OREGON			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	Rates As of 06/01/2011
Rate 01	O	**Bills**	13546.5	13531.3	13843.7	13535.2	13502.2	13524.7	13541.3	13509	13544.2	13695.3	13562.1	13599.2	162934.7	8.000000
		Min Bills	81.8	77.9	52.4	58.1	60.2	49.1	46.6	72.5	56.3	61.9	56.1	45.2	718.2	3.000000
		0-300	3,702,437	4,410,331	3,975,367	3,576,317	3,486,673	3,621,759	4,083,488	4,101,694	4,298,171	3,947,568	4,179,315	3,640,021	47,023,144	0.060253
		Over 300	21,328,593	18,206,380	15,234,883	12,196,220	8,408,300	7,675,633	9,764,140	12,506,550	10,119,621	8,150,413	10,625,860	17,602,685	151,819,275	0.073884
		Total kWh	25,031,030	22,616,711	19,210,250	15,772,537	11,894,973	11,297,392	13,847,628	16,608,244	14,417,792	12,097,981	14,805,175	21,242,706	198,842,419	
		Rev	1,907,542	1,719,380	1,476,049	1,225,045	939,520	893,673	1,075,926	1,279,463	1,115,178	949,786	1,145,562	1,628,808	15,355,932	
Rate 07	O	**1 phase**	2,043.7	2,048.2	2,059.7	2,074.7	2,070.5	2,065.3	2,067.8	2,070.7	2,071.5	2,123.8	2,095.8	2,089.4	24,881.1	8.600000
		3 phase	379.7	380.2	385.6	411.1	402.7	401.5	402.5	409.5	408.0	415.0	413.2	415.1	4,824.1	17.200000
		Total Bills	2,423.4	2,428.4	2,445.3	2,485.8	2,473.2	2,466.8	2,470.3	2,480.2	2,479.5	2,538.8	2,509.0	2,504.5	29,705.2	
		Min Bills	3.3	4.8	3.5	3.3	2.1	2.3	0.9	1.4	2.7	4.0	5.2	1.7	35.2	3.000000
		S 0-500	0	0	0	0	0	223,654	682,136	688,978	498,301	247	0	0	2,093,316	0.064775
		S Over	0	0	0	0	0	184,370	679,911	914,436	526,032	247	0	0	2,304,996	0.085776
		N 0-500	702,224	760,772	705,028	664,166	637,924	467,073	915	3,020	197,730	680,756	654,378	740,186	6,214,174	0.064775
		N Over	1,116,600	888,813	785,611	650,028	530,034	385,034	912	4,008	208,734	681,229	817,414	1,161,994	7,230,410	0.072819
		Total kWh	1,818,824	1,649,585	1,490,639	1,314,194	1,167,958	1,260,131	1,363,875	1,610,441	1,430,797	1,362,480	1,471,792	1,902,180	17,842,896	
		Rev	150,913	138,170	127,232	115,279	104,657	113,269	127,340	148,408	130,247	119,154	127,057	157,674	1,559,400	
Rate 09S	O	**1 phase**	386.5	380.9	375.4	367.1	360.5	353.3	349.5	341.5	346.0	353.1	346.9	348.7	4,309.5	9.500000
		3 phase	559.2	559.5	550.3	531.7	526.7	525.5	523.7	519.7	519.7	525.0	523.0	526.3	6,390.2	16.750000
		Total Bills	945.7	940.4	925.7	898.8	887.2	878.8	873.2	861.2	865.7	878.1	869.9	875.0	10,699.7	
		Min Bills	0.7	0.8	0.4	0.0	0.1	1.7	0.8	1.0	0.6	1.6	0.1	0.3	8.3	5.000000
		BLC	43,131	42,194	43,372	42,435	41,496	42,474	41,106	41,331	41,040	41,914	42,147	42,897	505,535	0.500000
		S kW	0	0	0	0	0	9,172	26,179	27,390	19,992	0	0	0	82,732	4.900000
		N kW	33,559	32,372	31,587	29,519	27,180	18,038	10	0	8,448	32,722	32,668	34,522	280,625	4.120000
		Total kW	33,559	32,373	31,588	29,519	27,180	27,210	26,188	27,390	28,441	32,722	32,668	34,522	363,359	
		S kWh	0	0	0	0	0	2,517,162	8,144,057	8,867,649	6,206,608	(93,092)	0	0	25,642,384	0.046904
		N kWh	11,978,742	11,039,001	9,871,002	8,210,173	7,060,406	5,201,344	3,645	0	2,573,759	9,619,384	10,846,626	12,209,753	88,613,835	0.043005
		Total kWh	11,978,742	11,039,001	9,871,002	8,210,173	7,060,406	7,718,506	8,147,702	8,867,649	8,780,366	9,526,292	10,846,626	12,209,753	114,256,218	
		Rev	688,016	642,194	589,112	508,310	448,608	494,413	543,113	582,757	567,078	577,244	634,183	700,887	6,975,915	
Rate 09P	O	**Bills**	5	5	5	5	5	5	5	5	5	5	5	5	60	200.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	3,758	3,603	3,535	3,783	3,747	3,864	3,708	3,794	3,716	3,715	3,634	3,487	44,344	0.970000
		S kW	0	0	0	0	0	0	2,767	2,822	3,007	0	0	0	8,596	4.700000
		N kW	3,152	3,055	2,841	2,955	2,881	3,089	0	0	0	2,842	2,741	2,815	26,370	4.350000
		Total kW	3,152	3,055	2,841	2,955	2,881	3,089	2,767	2,822	3,007	2,842	2,741	2,815	34,966	
		On-Peak kW	0	0	0	0	0	0	2,697	2,750	2,964	0	0	0	8,411	0.690000
		S On-Peak kWh	0	0	0	0	0	0	317,898	333,507	355,324	0	0	0	1,006,729	0.044884
		S Mid-Peak kWh	0	0	0	0	0	0	484,491	524,844	536,224	0	0	0	1,545,559	0.041992
		S Off-Peak kWh	0	0	0	0	0	0	343,326	389,499	364,290	0	0	0	1,097,115	0.040101
		NS Mid-Peak kW	871,730	841,838	781,368	819,719	754,824	721,715	0	0	0	736,725	722,011	772,931	7,022,860	0.037856
		NS Off-Peak kW	569,558	596,879	477,035	482,584	438,854	500,928	0	0	0	432,565	434,627	493,793	4,426,824	0.036648
		Total kWh	1,441,288	1,438,717	1,258,403	1,302,303	1,193,678	1,222,643	1,145,715	1,247,851	1,255,838	1,169,290	1,156,638	1,266,724	15,099,088	
		Rev	72,228	71,527	63,847	66,241	61,827	63,864	67,844	72,468	73,854	60,709	59,711	63,982	798,102	

2011 Retail Revenue Forecast Derivation

Rate 09T	O	**Bills**	1	1	1	1	1	1	1	1	1	1	1	1	12	200.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	1,152	922	993	1,318	1,089	1,003	1,260	1,215	1,200	1,319	1,093	1,168	13,732	0.300000
		S kW	0	0	0	0	0	0	1,048	1,031	1,036	0	0	0	3,114	3.590000
		N kW	1,095	666	814	1,149	1,026	918	0	0	0	1,071	920	1,009	8,667	3.840000
		Total kW	1,095	666	814	1,149	1,026	918	1,048	1,031	1,036	1,071	920	1,009	11,782	
		On-Peak kW	0	0	0	0	0	0	810	636	655	0	0	0	2,100	0.690000
		S On-Peak kWh	0	0	0	0	0	0	55,253	54,860	66,244	0	0	0	176,357	0.042176
		S Mid-Peak kWh	0	0	0	0	0	0	99,113	93,534	100,684	0	0	0	293,331	0.039483
		S Off-Peak kWh	0	0	0	0	0	0	54,898	61,158	54,364	0	0	0	170,420	0.037722
		NS Mid-Peak kW	182,973	117,537	112,482	190,231	140,547	102,639	0	0	0	149,870	132,432	173,392	1,302,103	0.035631
		NS Off-Peak kW	131,589	107,299	87,070	120,253	99,715	86,426	0	0	0	73,686	81,650	102,610	890,298	0.034507
		Total kWh	314,562	224,836	199,552	310,484	240,262	189,065	209,264	209,552	221,292	223,556	214,082	276,002	2,832,509	
		Rev	15,811	10,924	10,637	15,935	12,916	10,664	13,212	13,017	13,551	12,590	11,598	14,142	154,997	0.000000
Rate 19P	O	**Bills**	6	6	6	6	6	6	6	6	6	6	6	6	72	200.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	31,421	32,927	29,779	28,821	30,753	31,791	30,074	27,958	27,658	28,243	30,572	28,351	358,346	0.970000
		S kW	0	0	0	0	0	0	28,606	27,033	26,951	0	0	0	82,590	4.700000
		N kW	28,394	29,200	26,140	25,394	27,213	29,347	0	0	0	26,833	28,297	25,631	246,450	4.350000
		Total kW	28,394	29,200	26,140	25,394	27,213	29,347	28,606	27,033	26,951	26,833	28,297	25,631	329,040	
		On-peak kW	0	0	0	0	0	0	28,032	26,458	25,158	0	0	0	79,648	0.690000
		S On-peak kWh	0	0	0	0	0	0	3,797,705	3,453,505	3,735,554	0	0	0	10,986,763	0.047848
		S Mid-peak kWh	0	0	0	0	0	0	6,379,761	5,873,242	6,550,594	0	0	0	18,803,597	0.037752
		S Off-peak kWh	0	0	0	0	0	0	4,910,404	4,569,275	4,900,863	0	0	0	14,380,542	0.033390
		N Mid-peak kWh	8,382,482	9,160,268	8,475,578	8,862,918	8,304,009	9,281,142	0	0	0	8,136,145	8,730,308	7,952,340	77,285,191	0.035658
		N Off-peak kWh	6,339,832	7,207,180	5,999,476	6,388,021	5,902,128	7,400,806	0	0	0	5,902,527	6,788,372	5,804,613	57,732,954	0.032292
		Total kWh	14,722,314	16,367,448	14,475,054	15,250,939	14,206,137	16,681,948	15,087,870	13,896,021	15,187,011	14,038,672	15,518,680	13,756,953	179,189,047	
		Rev	658,821	719,531	639,752	661,938	636,101	729,631	770,682	713,167	761,735	626,043	684,463	611,201	8,213,065	0.000000
Rate 19T	O	**Bills**	1	1	1	1	1	1	1	1	1	1	1	1	12	200.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	9,003	4,179	8,569	22,566	11,437	6,195	18,651	18,219	17,334	21,497	11,837	15,581	165,068	0.300000
		S kW	0	0	0	0	0	0	18,195	17,533	16,701	0	0	0	52,429	3.590000
		N kW	8,898	2,439	4,609	20,986	11,242	5,918	0	0	0	19,174	11,528	15,326	100,121	3.840000
		Total kW	8,898	2,439	4,609	20,986	11,242	5,918	18,195	17,533	16,701	19,174	11,528	15,326	152,550	
		On-peak kW	0	0	0	0	0	0	18,166	17,390	16,426	0	0	0	51,982	0.690000
		S On-peak kWh	0	0	0	0	0	0	2,198,686	1,852,535	2,387,997	0	0	0	6,439,218	0.044001
		S Mid-peak kWh	0	0	0	0	0	0	3,959,159	3,595,692	4,513,253	0	0	0	12,068,104	0.035013
		S Off-peak kWh	0	0	0	0	0	0	3,209,134	3,192,790	3,598,917	0	0	0	10,000,842	0.031110
		N Mid-peak kWh	2,393,668	544,509	1,006,426	5,412,139	3,072,709	1,648,021	0	0	0	5,154,654	2,388,122	3,583,875	25,204,122	0.033017
		N Off-peak kWh	1,845,553	404,898	718,795	4,131,841	2,419,243	1,590,273	0	0	0	4,247,117	2,016,766	3,069,094	20,443,581	0.030022
		Total kWh	4,239,221	949,407	1,725,221	9,543,980	5,491,952	3,238,294	9,366,979	8,641,017	10,500,168	9,401,771	4,404,888	6,652,969	74,155,867	
		Rev	171,506	40,954	75,277	390,296	220,884	126,938	418,852	387,346	451,751	377,976	187,416	274,197	3,123,393	0.000000

2011 Retail Revenue Forecast Derivation

Rate 24S	O		**In Bills**	0	0	0	0	0	1603.1	1617	1629.7	1628.6	0	0	0	6478.4	15.000000
			Out-Bills	1543.3	1535.4	1541.4	1526.4	1550.7	0	0	0	0	1646.8	1592.7	1565.8	12502.5	3.000000
			Min Bills	7.6	1.3	8.7	21.3	40.5	6.2	1.0	0.8	13.2	88.7	33.5	23.8	246.7	3.000000
			In-kW	0	0	0	0	0	26,709	27,848	26,841	25,560	0	0	0	106,958	6.050000
			Out-kW	239	160	141	452	13,358	0	0	0	0	12,873	4,927	1,281	33,431	0.000000
			Total kW	239	160	141	452	13,358	26,709	27,848	26,841	25,560	12,873	4,927	1,281	140,390	
			In <164 kWh per	0	0	0	0	0	4,898,419	4,749,544	4,381,940	4,197,877	0	0	0	18,227,779	0.057355
			In >164 kWh per	0	0	0	0	0	3,645,842	5,292,660	6,988,854	5,435,849	0	0	0	21,363,206	0.055992
			Out-kWh	31,659	19,790	16,302	46,173	3,288,773	0	0	0	0	3,128,975	424,689	101,919	7,058,280	0.060939
			Total kWh	31,659	19,790	16,302	46,173	3,288,773	8,544,261	10,042,204	11,370,794	9,633,726	3,128,975	424,689	101,919	46,649,265	
			Rev	6,582	5,816	5,644	7,457	205,188	670,744	761,495	829,483	724,240	195,883	30,759	10,980	3,454,271	0.000000
Rate 40	O		**In Bills**	3	3	3	3	3	3	3	3	3	3	3	3	36	0.000000
			Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.500000
			kWh	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	12,900	0.075250
			Rev	81	81	81	81	81	81	81	81	81	81	81	81	972	0.000000
Rate 42	O		**In Bills**	6	6	6	6	6	6	6	6	6	6	6	6	72	0.000000
			kWh	1,363	1,353	1,355	1,362	1,366	1,361	1,367	1,365	1,359	1,359	1,365	1,353	16,328	0.075380
			Rev	103	102	102	103	103	103	103	103	102	102	103	102	1,231	0.000000
Rate 15	kWh/lamp		1csa	29,048	28,927	28,955	28,899	28,915	28,873	28,934	28,827	28,441	29,156	28,690	28,624	346,288	
kWh			2csa	4,737	4,782	4,833	4,810	4,810	4,810	4,828	4,736	4,943	4,788	4,709	4,736	57,522	
			2csf	1,628	1,616	1,628	1,628	1,615	1,628	1,628	1,655	1,699	1,628	1,628	1,628	19,611	
			4chf	0	0	0	0	0	0	0	0	0	0	0	0	0	
			4csa	2,355	2,356	2,355	2,355	2,355	2,355	2,355	2,355	2,458	2,355	2,355	2,355	28,366	
			4csf	2,670	2,670	2,669	2,669	2,669	2,669	2,669	2,669	2,786	2,670	2,669	2,669	32,149	
			1khf	0	0	0	0	0	0	0	0	0	0	0	0	0	
			Total kWh	40,438	40,351	40,440	40,361	40,365	40,335	40,415	40,243	40,327	40,597	40,052	40,012	483,936	
Lamps		39	1csa	745	742	742	741	741	740	742	739	729	748	736	734	8,879	9.620000
		74	2csa	64	65	65	65	65	65	65	64	67	65	64	64	778	15.380000
		74	2csf	22	22	22	22	22	22	22	22	23	22	22	22	265	18.660000
		155	4chf	0	0	0	0	0	0	0	0	0	0	0	0	0	30.930000
		157	4csa	15	15	15	15	15	15	15	15	16	15	15	15	181	24.370000
		157	4csf	17	17	17	17	17	17	17	17	18	17	17	17	205	27.670000
		362	1khf	0	0	0	0	0	0	0	0	0	0	0	0	0	56.220000
			Fac Chg	679	675	675	679	677	679	681	678	658	679	677	662	8,099	
			Min Bill	1.7	1.1	1.3	1.0	1.9	1.0	1.5	1.0	1.6	1.7	2.8	1.0	17.6	3.000000
			kWh	40,438	40,351	40,440	40,361	40,365	40,335	40,415	40,243	40,327	40,597	40,052	40,012	483,936	
			Rev	9,403	9,387	9,388	9,378	9,380	9,368	9,389	9,343	9,365	9,447	9,319	9,295	112,462	0.000000

2011 Retail Revenue Forecast Derivation

			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	Rates 6/1/2011
Rate 41A		39 100 S	839	839	839	839	839	838	838	838	838	838	838	838	10,061	8.320000
		74 200 S	165	166	166	166	165	165	165	165	165	165	165	165	1,983	10.000000
No New		100 250 S	26	25	25	25	26	26	26	26	26	26	26	26	309	11.040000
		157 400 S	84	84	69	83	83	83	83	83	83	83	84	84	986	13.710000
	O	**Bills**	14	14	14	14	14	14	14	14	14	14	14	14	168	
		kWh	66,171	65,529	63,059	65,115	64,538	63,931	64,188	64,107	64,583	65,169	65,507	66,211	778,108	0.000000
		Rev 41A	10,069	10,068	9,863	10,054	10,055	10,047	10,047	10,047	10,047	10,047	10,061	10,061	120,466	
		Rev All 41	10,412	10,379	10,169	10,352	10,323	10,270	10,283	10,279	10,303	10,333	10,356	10,392	123,851	
Rate 41B		155 400 M	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000000
		39 100S	1	1	1	1	1	1	1	1	1	1	1	1	12	4.980000
		74 200 S	17	17	17	17	17	9	9	9	9	9	9	9	148	6.680000
		100 250 S	1	1	1	1	1	1	1	1	1	1	1	1	12	7.700000
		157 400 S	1	1	1	1	1	1	1	1	1	1	1	1	12	10.370000
		Rev 41B	137	137	137	137	137	83	83	83	83	83	83	83	1,266	
Rate 41M	**O**	**Bills**	1	1	1	1	1	2	2	2	2	2	2	2	19	8.00
		kWh	3,898	3,282	3,175	3,025	2,422	2,446	2,703	2,622	3,098	3,684	3,865	4,575	38,795	0.05067
		Rev 41M	206	174	169	161	131	140	153	149	173	203	212	248	2,118	
SPECIAL CONTRACTS			**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**	**Rates 6/1/2011**
Rate 26	Micron	Bills	1	1	1	1	1	1	1	1	1	1	1	1	12	
		Contract kW	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	720,000	1.49
		kW	54,921	55,148	55,579	56,175	56,945	59,596	61,326	59,090	56,561	54,807	52,166	51,196	673,510	9.75
		kWh	39,386,440	36,062,408	39,784,047	38,524,155	39,665,707	39,824,511	42,075,363	40,663,092	37,667,121	37,587,216	36,240,611	37,171,405	464,652,076	0.018394
		Rev	1,349,354	1,290,425	1,363,083	1,345,720	1,374,225	1,402,993	1,461,263	1,413,484	1,333,719	1,315,148	1,264,628	1,272,292	16,186,334	0
Rate 29	Simplot	Bills	1	1	1	1	1	1	1	1	1	1	1	1	12	
		Contract kW	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	300,000	2.04
		kW	22,904	23,178	23,895	23,350	23,581	22,320	23,345	22,881	23,148	22,981	23,249	23,486	278,318	6.97
		kWh	15,842,223	14,367,398	15,944,449	15,450,270	15,860,635	9,659,161	15,917,496	15,740,845	15,009,653	15,582,774	15,359,841	16,024,052	180,758,797	0.01848
		Rev	503,405	478,060	512,202	499,270	508,464	385,072	507,870	501,371	489,720	499,147	496,895	510,822	5,892,298	0
Rate 30	DOE	Bills	1	1	1	1	1	1	1	1	1	1	1	1	12	
		kW	44,905	39,738	38,477	32,055	26,822	25,574	26,592	28,269	26,389	32,391	36,558	40,834	398,604	7.55
		kWh	27,896,545	23,272,401	22,715,786	18,590,950	16,151,630	15,597,710	15,849,666	15,063,852	15,176,116	18,862,047	21,143,195	24,780,102	235,100,000	0.019787
		Rev	891,022	760,513	739,979	609,874	522,098	501,716	514,387	511,499	499,527	617,775	694,373	798,621	7,661,384	0

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Matthew T. Larkin
Revenue Requirement by Functional Category

July 29, 2011

IDAHO POWER COMPANY
Revenue Requirement By Functional Category
State of Oregon
Test Year - 2011

	Total Revenue Requirement	% of Total
Generation		
Demand-Related	$ 10,427,415	22.8%
Energy-Related	15,370,848	33.6%
Transmission	4,573,960	10.0%
Distribution		
Demand-Related	11,661,526	25.5%
Customer-Related	3,687,669	8.1%
Total	$ 45,721,417	100.0%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Matthew T. Larkin
Marginal Cost Analysis

July 29, 2011

2011 Marginal Cost Analysis – Technical Description

The following is a technical description of the 2011 Marginal Cost Analysis. The concept and design of the 2011 Marginal Cost Analysis is from the National Economic Research Associates, Inc. ("NERA") marginal cost model. The NERA model is constantly being refined but the basic concepts and methods have remained the same since Idaho Power began using this method. In this analysis, forecasted growth-related generation, transmission and distribution costs are identified and classified into the appropriate energy-, demand- and customer-related components for use in the Company's class cost-of-service model. The energy-related marginal costs include net power supply costs, variable operation and maintenance (O&M) expenses, fuel inventory and losses. Demand-related costs are comprised of generation, transmission and distribution capacity investment and associated fixed O&M expenses. Customer-related costs include investment costs that are attributable to anticipated growth in the number of customers served.

Generation Marginal Costs

Marginal Cost of Energy. The marginal costs of energy were determined from the simulated operation of the Company's power supply system over 83 streamflow conditions for the five-year period 2011 through 2015. Base case net power supply expenses were quantified and the model was run a second time with fifty megawatts of load added across all hours. The monthly difference in power supply expenses between the base run and the "base-plus-50-MW run" was averaged over the five-year period and divided by the difference in monthly megawatt hours to produce an average monthly marginal cost per megawatt hour. The 2011 test year net power supply run was used for the 2011 base marginal cost run. For the years 2012 through 2015, projected loads along with currently planned resource additions at the time of the study were used. The 2011 test year gas prices were used, adjusted for each of the successive years using the Bureau of Labor Statistics: Produce Price Index; Moody's Analytics. Coal plant operating characteristics, with the exception of coal costs, and CSPP purchased power volumes from the 2011 analysis were used for the entire period, 2011 through 2015. Added to the average monthly marginal cost per megawatt hour was the revenue requirement associated with marginal fuel inventory, and the marginal variable O&M expense. This loaded energy cost was then increased for losses at the transmission and distribution levels of service. Complete monthly marginal energy costs can be found on Schedule 1.

Marginal Cost of Generation Capacity. The annual marginal cost of generation capacity was derived from the inclusion of the Danskin CT1 Power Plant into rate base (Case No. IPC-E-08-1) and from Idaho Power's 2011 Integrated Resource Plan ("IRP"). The peaking resource selected from the resource portfolio to quantify the marginal cost of capacity was the Danskin CT1 Combustion Turbine. Plant investment included in the Company's application was used and fixed O&M expenses were obtained from the 2011 IRP Technical Appendix, p.82. The reserve margin is 10% (2011 IRP). The marginal cost of generation capacity can be found on Schedule 2, page 1 of 2.

Seasonalization of Marginal Cost of Generation Capacity. The seasonalization of the marginal cost of generation capacity is based on information from the 2011 IRP. The Company plans new peaking generation capacity based on monthly peak hour load surplus/deficiency data, assuming 90th percentile streamflow conditions, 70th percentile average load and 95th percentile peak-hour load (2011 IRP Technical Appendix). On this basis, during the five years 2011 through 2015, the IRP identified the months of June, July, August, September, and December as months of anticipated deficiency. These are the months that were assigned generation capacity costs in the 2011 Marginal Cost Analysis. The relative sizes of the five-year average monthly deficiencies were used to define the share of annual capacity cost assigned to each month as shown on Schedule 2, page 2 of 2.

Marginal Cost of Transmission Capacity

The marginal cost of transmission reflects planned investment included in the capital budget for the next ten years. The investment costs are for the years 2011 through 2020. Demand related transmission O&M was estimated using historic data for the period 2006 through 2010. Marginal transmission costs are displayed on Schedule 3, page 1 of 2.

<u>Seasonalization of the Marginal Cost of Transmission.</u> The marginal cost of transmission capacity represents the sum of two distinct components; 1) network integration cost associated with integrating a new network resource to meet native load service requirements and 2) the costs associated with planned transmission system expansion. Since the resource integration portion of marginal transmission investment is driven by the need for new generation resources, as identified in the 2011 IRP, these costs were assigned to months in the same manner as the marginal cost of generation capacity. The investment in the second component of costs, new system expansion, is driven by peak load growth on the system, irrespective of the introduction of new resources onto the grid. Therefore, that portion of marginal costs is assigned to the months based on relative monthly peak load growth from 2011 through 2020. The two components are summed by month. This method results in the assignment of marginal costs of transmission capacity to each of the twelve months of the year. The seasonal assignment of marginal transmission capacity costs can be found on Schedule 3, page 2 of 2.

Distribution Marginal Costs

To quantify marginal distribution costs, the Company used the "facilities cost method," as described by NERA. Under this method costs are divided into three categories: costs that increase with growth in actual peak demand, design demand-related costs, and customer-related costs. The first category is comprised of distribution substation carrying costs and related O&M expenses. The second category is comprised of the carrying costs of plant located between the distribution substation and the service drop, as well as associated O&M expense. This includes primary lines, secondary lines, poles, transformers and associated equipment. The service drop is considered by NERA to be part of the design demand-based category, but Idaho Power's practice is to include the service drop in customer-related costs. The Company deviates from NERA methodology in this manner because the costs of the service drop are the direct result of providing service to a specific new customer, and do not vary with changes in the customer's load. By categorizing service drops as customer-related, the Company believes that a more precise attribution of customer cost responsibility to classes results than would otherwise be the case. Customer-related costs also include the carrying cost of the meter and associated O&M expense, customer service & informational expense, and customer accounts expense.

Distribution Substation Costs. In order to quantify growth-related distribution substation costs, projected investment in new upgrades and substation was identified for the period 2011 through 2015. The forecast growth in distribution peak load was derived by multiplying the forecast system peak load (2011 IRP Technical Appendix, p. 4-5) by a percentage that reflects the 2010 ratio of distribution peak load to total system peak load. Projected investment was then divided by forecast growth in distribution peak load to arrive at marginal distribution substation cost per kW as shown on Schedule 4, page 1 of 2. Marginal distribution substation O&M expense was developed using the Company's total forecast annual distribution O&M expense for the planning period, to which a ratio was applied reflecting the historical relationship between distribution substation O&M expense and total distribution O&M expense. The forecast annual distribution substation O&M expenses were then divided by the forecast distribution peak load and averaged, resulting in marginal distribution substation O&M cost per kW as shown on Schedule 4, page 2 of 2.

Marginal Distribution Facilities Cost. The second cost category is distribution facilities cost, which covers distribution components between the substation and the service drop, as well as associated O&M expense. The first step in quantifying these costs was to price each feeder on the system at current prices. These costs were then allocated to rate classes based on the relative demand of each class by feeder. Finally, each rate class's total cost was divided by its share of total feeder capacity to arrive at a marginal distribution facilities cost per kW, which can be found on Schedule 5, page 1 of 2. Marginal distribution facilities O&M expense was developed using the Company's total forecast annual distribution O&M expense for the planning period, to which a ratio was applied reflecting the historical relationship between distribution facilities O&M expense and total distribution O&M expense. The forecast annual distribution facilities O&M expense was then divided by the forecast peak load and averaged, resulting in marginal distribution facilities O&M cost per kW as shown on Schedule 5, page 2 of 2. Per NERA methodology, it was assumed that marginal distribution facilities O&M expense for a secondary customer is twice the expense of a primary customer.

Marginal Meter Cost. Marginal meter investment per customer for each rate class was developed by determining the types of meters the Company is currently installing for each rate class, then pricing these meters at current cost. A summary of these costs by rate class can be found on Schedule 6, page 1 of 4. Associated O&M was developed using the Company's total forecast annual distribution O&M expense for the planning period, to which a ratio was applied reflecting the historical relationship between meter O&M expense and total distribution O&M expense. A weighted number of customers by class was then derived by multiplying the number of customers in each class by a factor reflecting the relative cost of meters per customer. This calculation is illustrated on Schedule 6, page 4 of 4. The forecast annual meter O&M expenses were then divided by the forecast number of weighted customers to arrive at a system average expense in dollars per weighted customer for each year of the planning period. The results for the five years were then averaged, producing a system average meter O&M expense per weighted customer, displayed on Schedule 6, page 3 of 4. This system average was multiplied by class factors based on relative meter cost to estimate the expense for each actual customer by rate class as shown on Schedule 6, page 2 of 4.

Marginal Service Drop Costs. The cost of the service drop was developed for both single-phase and three-phase service. A weighted cost was applied to each rate class based on the proportion of single-phase to three-phase meters of new meter installs during the period January through December 2010. Only overhead service was calculated because the Company has a rule in place that provides for a charge to the customer when underground service attachments are desired. The costs of both a single-phase and three-phase drop are shown on Schedule 7, along with the relative percentages of single-phase and three-phase customers by rate class.

<u>Marginal Customer Accounts Expense.</u> To estimate marginal customer accounts expense, total customer accounts expense was forecasted for each of the years 2011 through 2015. These annual expense amounts were then divided by the forecasted number of weighted customers for the same time period. The result was a system average expense in dollars per weighted customer for each year of the planning period. The weighted number of customers was derived by multiplying the number of customers in each class by a factor reflecting the relative size of this expense, per customer, for each class. This calculation is illustrated on Schedule 8, page 3 of 3. The average expense values for the five years were then averaged, producing a system average customer accounts expense per weighted customer as displayed on Schedule 8, page 2 of 3. This system average was then multiplied by the class factors to arrive at customer accounts expense per actual customer by class as shown on Schedule 8, page 1 of 3.

<u>Marginal Customer Service & Informational Expense.</u> Customer service & informational expense was forecasted for the planning period 2011 through 2015, then divided by the forecast number of customers for the same period and averaged, producing marginal customer service & informational expense per customer as shown on Schedule 9. It is assumed that customer service & informational expense per customer does not vary greatly across classes, so these costs were not weighted in the same manner as other customer-related costs.

<u>Development of Marginal Annual Distribution Costs.</u> To arrive at marginal annual distribution costs, both substation and facilities costs were adjusted in the same manner. First, these costs were adjusted for general plant loading, then the annual economic carrying charge was applied and A&G loading was added. Related expenses were adjusted for A&G loading, and the revenue requirement for working capital was added, resulting in total annual marginal distribution costs per kW. A summary of annual marginal distribution substation costs and annual marginal distribution facilities costs can be found on Schedules 10 and 11, respectively. Customer-related costs were adjusted for carrying charges and loading in a similar manner. Meter investment and the service drop were adjusted for general plant loading, the annual economic carrying charge was applied and A&G loading was added. Related expenses were adjusted for A&G loading, and the revenue requirement for working capital was added, resulting in total annual customer-related marginal distribution costs per customer as shown on Schedule 12.

<u>Development of Loaders and Factors.</u> Annual economic carrying charge rates were prepared for a combustion turbine, transmission plant, and distribution plant. The carrying charges reflect the 2011 test year weighted cost of capital and resource lives of each asset as derived in the Company's 2003 depreciation study. A summary of these charges can be found on Schedule 13. General plant, administrative & general, and materials & supplies loading factors were derived from an average of historic data from the period 2006 through 2010. The factor representing the revenue requirement percentage for

working capital was derived using the Company’s 2011 test year weighted cost of capital and expected tax rates. A summary of loaders is displayed on Schedule 14.

SCHEDULE 1

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Marginal Cost of Energy - Dollars/MWh

Line		January	February	March	April	May	June	July	August	September	October	November	December	Annual Avg.
(1)	Marginal Generation Cost at Generation 1/	$34.09	$31.36	$29.96	$27.54	$28.37	$25.65	$41.56	$42.10	$38.57	$39.12	$40.16	$45.03	$35.70
(2)	Marginal Fuel Inventory	$22.07	$22.07	$22.07	$22.07	$22.07	$22.07	$22.07	$22.07	$22.07	$22.07	$22.07	$22.07	
(3)	Cost of Capital & Taxes for Fuel Inventory (2) x 11.62% 2/	$2.56	$2.56	$2.56	$2.56	$2.56	$2.56	$2.56	$2.56	$2.56	$2.56	$2.56	$2.56	
(4)	Marginal Variable O & M 3/	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	
(5)	Marginal energy cost at Generation	$38.65	$35.92	$34.52	$32.10	$32.93	$30.21	$46.12	$46.66	$43.13	$43.68	$44.72	$49.59	
	Average System Loss Factor Coefficients at: 4/													
(6)	Transmission	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	
(7)	Distribution Station	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	
(8)	Distribution Primary	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	
(9)	Distribution Secondary	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	
	Marginal Energy Cost at Service Level													
(10)	Power Supply (5)	$38.65	$35.92	$34.52	$32.10	$32.93	$30.21	$46.12	$46.66	$43.13	$43.68	$44.72	$49.59	$39.85
(11)	Transmission (6) x (5)	$40.01	$37.18	$35.73	$33.23	$34.09	$31.27	$47.74	$48.30	$44.64	$45.21	$46.29	$51.33	$41.25
(12)	Distribution Station (7) x (5)	$40.59	$37.72	$36.25	$33.71	$34.58	$31.73	$48.43	$49.00	$45.29	$45.87	$46.96	$52.07	$41.85
(13)	Distribution Primary (8) x (5)	$41.51	$38.58	$37.08	$34.48	$35.37	$32.45	$49.54	$50.12	$46.33	$46.92	$48.03	$53.26	$42.81
(14)	Distribution Secondary (9) x (5)	$42.87	$39.84	$38.29	$35.60	$36.52	$33.51	$51.15	$51.75	$47.84	$48.45	$49.60	$55.00	$44.20

1/ Aurora Power Supply Model 2011 to 2015
2/ Schedule 14. Based on 2011 Test Year Cost of Capital
3/ IPCo 2011 IRP Technical Appendix - Page 82
4/ Schedule 15

IDAHO POWER COMPANY
MARGINAL COST ANALYSIS 2011
ANNUAL GENERATION CAPACITY COST: DOLLARS PER KW

(1)	Investment ($/kw) 1/	$339.12
(2)	General Plant Loading (1) x 1.08 2/	$366.68
(3)	Economic Carrying Charge Rate 3/	7.18%
(4)	A&G Loading .53% 4/	0.53%
(5)	Total Carrying Charge	7.71%
(6)	Annual Cost ($/kw) (2) x (5)	$28.26
(7)	Demand related fixed O&M 5/	$4.00
(8)	A&G loading (7) x 1.399 6/	$5.60
(9)	Marginal Demand Related Costs (6) + (8)	$33.85
	Working Capital	
(10)	Materials & Supplies (2) x 1.14%	$4.17
(11)	Revenue Requirement for Materials & Supplies (10) x 11.62%	$0.48
(12)	Total Marginal Demand Related Costs (9) + (11) rounded	$34.34
(13)	Adjusted for reserve margin (10%) 7/	**$38.00**

Notes

1/ Total Investment of Danskin CT1 $57,650,861 / 170 MW (Case No. IPC-E-08-01, Exhibit 2)

2/ Schedule 14. Average general plant loading 2006-2010

3/ Schedule 13. Based on 2011 Test Year Cost of Capital

4/ Average A & G expenses 2006 - 2010 applicable to plant related expenses, Schedule 14

5/ Estimated cost of a simple cycle combustion turbine , IPCo 2011 IRP Technical Appendix, Page 82

6/ Average A & G expenses 2006 - 2010 applicable to non-plant related expenses, Schedule 14

7/ IPCo 2011 IRP - Page 115

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Seasonalized Generation Capacity Marginal Costs

		(1)	(2)	(3)
				Monthly
		% Share	**$/kw/year**	**Marginal**
		of Total 1/	**$38.00**	**Cost**
	Month			(1) X (2)
(1)	**Jan**	0.00%		0.00
(2)	**Dec**	0.00%		0.00
(3)	**Mar**	0.00%		0.00
(4)	**Apr**	0.00%		0.00
(5)	**May**	0.00%		0.00
(6)	**Jun**	22.20%		8.44
(7)	**Jul**	30.30%		11.51
(8)	**Aug**	9.13%		3.47
(9)	**Sep**	33.45%		12.71
(10)	**Oct**	0.00%		0.00
(11)	**Nov**	0.00%		0.00
(12)	**Dec**	4.93%		1.87
(13)	**Sum**	100.00%		38.00

Notes
1/ G & T Assignment Factors Workpaper
seasonalized based on average monthly share of peak hour deficiencies
for the five year period 2011-2015. Source: 2011 IRP Technical Appendix

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Annual Transmission Marginal Costs
Dollars/kw

		Integration of New Resources	Planned System Expansion	Total
		(1)	(2)	(1) + (2)
(1)	Investment ($/kw)	$52.55	$1,744.69	
(2)	With General Plant Loading (1) x 1.08 1/	$56.82	$1,886.50	
(3)	Economic Carrying Charge Rate 2/	6.12%	6.12%	
(4)	A&G Loading .53% 3/	0.53%	0.53%	
(5)	Total Carrying Charge	6.65%	6.65%	
(6)	Annual Cost ($/kw) (2) x (5)	$3.78	$125.39	
(7)	Demand related O&M 4/	$6.72	$6.72	
(8)	With A&G loading (7) x 1.399 5/	$9.40	$9.40	
(9)	Marginal Demand Related Costs (6) + (8)	$13.18	$134.79	
	Working Capital			
(10)	Materials & Supplies (2) x 1.14%	$0.65	$21.43	
(11)	Revenue Requirement and Taxes for Materials & Supplies (10) x 11.62% 6/	$0.08	$2.49	
(12)	Total Marginal Demand Related Costs (9) + (10) + (11) Rounded	$13.26	$137.28	
(13)	Total Annual Transmission Marginal Costs (rounded)	**$13.00**	**$137.00**	**$ 150.00**

Notes:

1/ Average general plant loading 2006 - 2010, Schedule 14
2/ Schedule 13. Based on 2011 Test Year Cost of Capital
3/ Average A & G expenses 2006 - 2010 applicable to plant related expenses, Schedule 14
4/ Average O& M 2006 - 2010 w/o accts. 565 & 567
5/ Average A & G expenses 2006 - 2010 applicable to non-plant related expenses, Schedule 14
6/ Schedule 14. Based on 2011 Test Year Cost of Capital

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Seasonalized Transmission Marginal Costs
Dollars / kW

		Integration of New Resources			Planned System Expansion			TOTAL
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
		% Share of Total 1/	$/kw/year 2/ $13.00	Monthly Marginal Cost	% Share of Total 3/	$/kw/year 4/ $137.00	Monthly Marginal Cost	Monthly Marginal Cost
	Month			(1) X (2)			(1) X (2)	(3) + (6)
(1)	Jan	0.00%		$0.00	5.03%		$6.89	6.89
(2)	Feb	0.00%		$0.00	3.58%		$4.90	4.90
(3)	Mar	0.00%		$0.00	4.20%		$5.75	5.75
(4)	Apr	0.00%		$0.00	2.68%		$3.67	3.67
(5)	May	0.00%		$0.00	9.52%		$13.05	13.05
(6)	Jun	22.20%		$2.89	14.84%		$20.33	23.22
(7)	Jul	30.30%		$3.94	16.28%		$22.30	26.24
(8)	Aug	9.13%		$1.19	13.66%		$18.72	19.91
(9)	Sep	33.45%		$4.35	12.04%		$16.50	20.85
(10)	Oct	0.00%		$0.00	6.30%		$8.63	8.63
(11)	Nov	0.00%		$0.00	5.66%		$7.75	7.75
(12)	Dec	4.93%		$0.64	6.20%		$8.50	9.14
(13)	Sum	100.00%		$13.00	100.00%		$137.00	150.00

Notes:
1/ Seasonalized based on average monthly share of peak hour deficiencies for the five year period 2011-2015. Source: 2011 IRP Technical Appendix G & T Assignment Factors Workpaper
2/ Schedule 3, page 1 of 2
3/ Seasonalized based on monthly share of peak hour load growth between 2011 and 2020 Source: 2011 IRP Technical Appendix G & T Assignment Factors Workpaper
4/ Schedule 3, page 1 of 2

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Derivation of Marginal Distribution Substation Investment

(1)	Investment in Load Related Additions to Distribution Substation Plant, 2011 - 2015 (Thousands of 2010 Dollars)	$37,251
(2)	Additions to Distribution Peak Load 2011 - 2015 in MW	331
(3)	Marginal Investment in Load Related Distribution Substation Facilities per Kilowatt (2010 Dollars) (1) / (2)	$\boxed{\textbf{\$112.63}}$

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Distribution Substation O&M Expenses per kW of Distribution Peak Load
(2010 dollars)

	Year	Total Distribution Substation Expenses 1/ (Thousand Dollars)	Distribution Peak Load (MW)	Substation Expenses Per kW of Peak Load (Dollars)
				(1) / (2)
		(1)	(2)	(3)
(1)	2011	$5,644	3,429	1.65
(2)	2012	$5,654	3,489	1.62
(3)	2013	$5,618	3,594	1.56
(4)	2014	$5,626	3,678	1.53
(5)	2015	$5,639	3,760	1.50

(6) Estimated Annual Distribution Substation O&M Expenses for the Planning Period **$1.57 per kw**

1/ Distribution substation expenses are total substation O&M expenses (Accounts 582 and 592) and overheads allocated to substation O&M expenses. Operation overheads (Accounts 580 and 588) and maintenance overheads (Account 590) were allocated to substations based on the relative importance of these expenses in total operation and maintenance (excluding overhead), respectively.

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Distribution Facilities Investment by Rate Class

Rate 01	$444
Rate 07	$280
Rate 09P	$233
Rate 09S	$350
Rate 19P	$137
Rate 24	$399
Rates 15,41,42	$278
Rate 40	$358

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Distribution Facilities O&M Expenses per kW
(2010 dollars)

	Year	Distribution Facilities O&M Expenses 1/	Total Peak Distribution Loads	O&M Expense Per kw	O&M Expense Per kW of Demand Secondary	O&M Expense Per kW of Demand Primary
		--(1000 Dollars)--	-- (MW)) --	---- (Dollars) ---- (1) / (2)	(2010 dollars) .5 x (3)	(2010 dollars) .5 x (3)
		(1)	(2)	(3)	(4)	(5)
(1)	2011	$24,458	3,429	$7.13	$3.57	$3.57
(2)	2012	$24,501	3,489	$7.02	$3.51	$3.51
(3)	2013	$24,345	3,594	$6.77	$3.39	$3.39
(4)	2014	$24,379	3,678	$6.63	$3.31	$3.31
(5)	2015	$24,436	3,760	$6.50	$3.25	$3.25
(6)	Est. Annual Distribution Facilities O&M Expenses for the Planning Period				$3.41	$3.41

(7) Estimated Annual Distribution Facilities O&M Expenses for a Primary Customer **$3.41**

(8) Estimated Distribution Facilities O&M Expense for a Secondary Customer: **$6.82**

1/ Distribution facilities expenses are total distribution O&M expenses excluding rents (Account 589), meter expenses (Accounts 586 and 597), street lighting expenses (Accounts 585 and 596), substation expenses (Accounts 582 and 592), expenses related to subtransmission, and overheads allocated to meters and street lighting, substation and subtransmission expenses. Operation overheads (Accounts 580 and 588) and maintenance overheads (Account 590) were allocated to facilities expenses based on the relative importance of these expenses in total operation and maintenance expenses (excluding overheads).

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
SUMMARY OF INSTALLED METERS BY CLASS
(2010 Dollars)

	Rate	Class	Investment
(1)	Rate 01	Residential	$378
(2)	Rate 07	Commercial	$429
(3)	Rate 09 - P	Commercial	$10,024
(4)	Rate 09 - S	Commercial	$666
(5)	Rate 09 - T	Commercial	$10,024
(6)	Rate 19 - P	Industrial	$13,276
(7)	Rate 19 - T	Industrial	$13,276
(8)	Rate 24	Irrigation	$424
(9)	Rates 41,42	Metered Lighting	$375

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Meter O&M Expense by Customer Class
(2010 dollars)

	Rate		Class	Weighting Factor	Annual Meter Expense Per Customer
				(1)	(1) x $14.19 (2)
(1)	Residential Service	1		1.01	$14.33
(2)	Small General Service	7		1.14	16.18
(3)	Large General Service	9P	Primary	26.73	379.30
(4)	Large General Service	9S	Secondary	1.78	25.26
(5)	Large General Service	9T	Transmission	26.73	379.30
(6)	Uniform Rate - Industrial	19P	Primary	35.40	502.33
(7)	Uniform Rate - Industrial	19T	Transmission	35.40	502.33
(8)	Irrigation	24		1.13	16.03
(9)	Metered Lighting	41,42		1.00	14.19

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Meter O&M Expense per Weighted Customer
(2010 dollars)

	Year	Total Meter Operation Maintenance Expenses 1/ (Thousand Dollars)	Average Number of Customers	Weighted Average Number of Customers	Meter Expense Per Weighted Customer (Dollars)
				(2) x 1.09 2/	[(1) x 1000]/(3)
		(1)	(2)	(3)	(4)
(1)	2011	$7,996	498,393	543,248	$14.72
(2)	2012	$8,010	507,310	552,968	14.49
(3)	2013	$7,959	516,390	562,865	14.14
(4)	2014	$7,970	525,634	572,941	13.91
(5)	2015	$7,989	535,046	583,200	13.70

(6) Estimated Annual Weighted Meter O&M Expense for the Planning Period 3/ **$14.19**

1/ Total meter expenses are meter operation and maintenance expenses (Accounts 586 and 597) and overheads allocated to meters. Operation overheads (Accounts 580 and 588) and maintenance overheads (Account 590) were allocated to meters expense based on the relative importance of these expenses to total distribution O&M (excluding overhead).
2/ Schedule 6, page 4
3/ Average of 2011 - 2015

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Development of Electric Meter Weighting Factors

	Customer Class			Installed Meter Cost 2010	Weight	Actual Avg 2010 Number of Customers	Weighted Number of Customers	Meter O&M Weighting Factor
					(1) / 375.00		(2) x (3)	(4) / (3)
				(1)	(2)	(3)	(4)	(5)
(1)	Residential Service	1		$378.00	1.01	407,374	411,448	
(2)	Small General Service	7		$429.00	1.14	31,289	35,669	
(3)	Large General Service	9P	Primary	$10,024.00	26.73	180	4,798	
(4)	Large General Service	9S	Secondary	$666.00	1.78	30,290	53,915	
(5)	Large General Service	9T	Transmission	$10,024.00	26.73	3	80	
(6)	Uniform Rate - Industrial	19	P & S	$13,276.00	35.40	117	4,139	
(7)	Uniform Rate Industrial	19T	Transmission	$13,276.00	35.40	4	142	
(8)	Irrigation	24		$424.00	1.13	17,745	20,052	
(9)	Metered Lighting	41,42		$375.00	1.00	162	162	
						487,164	530,406	**1.09**

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Investment Cost of the Service Drop

Single Phase	$254
Three Phase	$349

	Rate 01	Rate 07	Rate 09-P	Rate 09-S	Rate 09 T	Rate 19	Rate 19 T	Rate 24	Rate 42
Percent Single Phase	100%	67%	n/a	31%	n/a	n/a	n/a	27%	94%
Percent Three Phase	0%	33%	n/a	69%	n/a	n/a	n/a	74%	6%

SCHEDULE 7

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Customer Accounts Expense by Customer Class
(2010 Dollars)

	Customer Class		Weighting Factor 1/	Annual Customer Accts Expense Per Customer
				$39.50 2/
			(1)	(2)
(1)	Residential Service	1	1	$39.50
(2)	Small General Service	7	1	$39.50
(3)	Large General Service	9P	1	$39.50
(4)	Large General Service	9S	1	$39.50
(5)	Large General Service	9T	1	$39.50
(6)	Uniform Rate - Industrial	19	14	$553.00
(7)	Uniform Rate Industrial	19T	14	$553.00
(8)	Irrigation	24	1	$39.50
(9)	Lighting	40,41,42	1	$39.50

1/ Schedule 8, page 3
2/ Schedule 8, page 2

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Customer Accounts Expense per Weighted Customer
(2010 Dollars)

			2011 (1)	2012 (2)	2013 (3)	2014 (4)	2015 (5)
(1)	Customer Accounts Expenses (Thousand Dollars)		$20,443	$20,478	$20,348	$20,376	$20,424
(2)	Customers 1/		498,393	507,310	516,390	525,634	535,046
(3)	Weighted Customers Weighting Factor =	1.00	498,393	507,310	516,390	525,634	535,046
(4)	Expense per Weighted Customer (Dollars) [(1) / (3)] x 1000		$41.02	$40.37	$39.40	$38.76	$38.17
(5)	Estimated Annual Expense Per Customer For the Planning Period	2/	--------------	--------------	**$39.50**	-------------	-------------

1/ Average number of customers
2/ Average of 2011 - 2015

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
2010 Customer Accounts Expense by Rate Class

	Account 901		Account 902	Account 903	Account 904	Account 905		Total Expense	2010 Avg Customers	Cost Per Customer	Customer Weights	Weighted Customers
	Total #902 - #905	Allocated Expense				Total #902 - #904	Allocated Expense					
Residential	18,455,748	343,920	3,117,431	10,750,823	4,587,208	18,455,462	286	18,799,669	407,374	46.15	1	407,374
Commercial 7	1,196,078	22,289	297,053	824,613	74,394	1,196,060	19	1,218,367	31,289	38.94	1	31,289
Commercial 9	1,559,064	29,053	315,006	849,524	394,509	1,559,039	24	1,588,117	30,472	52.12	1	30,472
Uniform Contracts (19)	76,908	1,433	44,520	32,387	0	76,907	1	78,341	121	647.88	14	1,693
Irrigation	674,086	12,562	246,940	460,885	(33,749)	674,076	10	686,647	17,745	38.69	1	17,745
Unmetered General Service	53,986	1,006	0	52,199	1,786	53,985	1	54,992	1,979	27.79	1	1,979
Municipal Street Lighting	9,224	172	1,148	8,017	58	9,223	0	9,396	304	30.91	1	304
Traffic Control Lighting	11,710	218	2,496	9,214	0	11,710	0	11,928	349	34.15	1	349
Special Contracts	2,630	49	1,562	1,068	0	2,630	0	2,679	4	669.76	15	60
TOTAL	22,039,434	410,702	4,026,156	12,988,730	5,024,206	22,039,092	342	22,450,136	489,638			491,266

Weighting Factor: 1.00

SCHEDULE 9

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Customer Service and Informational Expense
(2010 Dollars)

		2011	2012	2013	2014	2015
		(1)	(2)	(3)	(4)	(5)
(1)	Customer Service and Informational Expenses (Thousand Dollars)	$7,682	$7,696	$7,647	$7,657	$7,676
(2)	Customers 1/	498,393	507,310	516,390	525,634	535,046
(3)	Weighted Number of Customers (2) x 1	498,393	507,310	516,390	525,634	535,046
(4)	Expense Per Customer (2010 Dollars) [(1) / (3)] x 1000	$15.41	$15.17	$14.81	$14.57	$14.35
(5)	Estimated Annual Expense Per Customer For the Planning Period 2/	------------------	------------------	**$14.90**	------------------	------------------

1/ Average number of customers
2/ Average of 2011 - 2015

SCHEDULE 10

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Annual Distribution Substation Unit Costs
(2010 dollars)

			Distribution Substation
(1)	Marginal Investment per kW	1/	$112.63
(2)	With General Plant Loading (1) x 1.08	2/	121.78
(3)	Annual Economic Carrying Charge Related to Capital Investment	3/	6.57%
(4)	A&G Loading (Plant Related)	4/	0.53%
(5)	Total Annual Carrying Charge (3) + (4)		7.10%
(6)	Annualized Costs (2) x (5)		$8.64
(7)	Demand Related O&M Expenses	5/	1.57
(8)	With A&G Loading (7) x 1.399 (Non-Plant Related)	6/	2.20
(9)	Demand-Related Cost (6) + (8)		$10.84
	Working Capital		
(10)	Material and Supplies (2) x 1.14%	7/	$1.38
(11)	Total Working Capital (10)		$1.38
(12)	Revenue Requirement for Working Capital (11) x 11.62%	8/	0.16
(13)	Total Demand Related Costs (9) + (12)		$11.00
(14)	Total Annual Marginal Cost per kW		**$11.00**

1/ Schedule 4, page 1
2/ Schedule 14
3/ Schedule 13
4/ Schedule 14
5/ Schedule 4, page 2
6/ Schedule 14
7/ Schedule 14
8/ Schedule 14

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Derivation of Annual Distribution Facilities Unit Costs

			Residential	Commercial			Industrial	Irrigation	Lighting	Unmetered General
			Rate 01	Rate 07	Rate 09 - P	Rate 09 - S	Rate 19 - P	Rate 24 & 25	Rates 15,41,42	Rate 40
(1)	Marginal Investment per kw	1/	$444.35	$279.86	$232.70	$349.81	$136.58	$399.28	$278.03	$357.88
(2)	With General Plant Loading (1) x 1.08	2/	480.47	302.61	251.61	378.24	147.68	431.73	300.63	386.97
(3)	Annual Economic Carrying Charge Related to Capital Investment	3/	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%
(4)	A&G Loading (plant-related)	4/	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
(5)	Total Annual Carrying Charge (3) + (4)		7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
(6)	Annualized Costs (2) x (5)		$34.10	$21.48	$17.86	$26.84	$10.48	$30.64	$21.33	$27.46
(7)	Facilities Investment O&M Expenses	5/	$6.82	$6.82	$3.41	$6.82	$3.41	$6.82	$6.82	$6.82
(8)	With A&G Loading [(7)] x 1.399 (non plant related)	6/	$9.54	$9.54	$4.77	$9.54	$4.77	$9.54	$9.54	$9.54
(9)	Facilities Investment Cost (6) + (8)		$43.64	$31.01	$22.63	$36.38	$15.25	$40.18	$30.87	$37.00
	Working Capital									
(10)	Materials and Supplies (2) x 1.14%	7/	$5.46	$3.44	$2.86	$4.30	$1.68	$4.91	$3.42	$4.40
(11)	Total Working Capital		$5.46	$3.44	$2.86	$4.30	$1.68	$4.91	$3.42	$4.40
(12)	Revenue Requirement for Working Capital (12) x 11.62%	8/	$0.63	$0.40	$0.33	$0.50	$0.19	$0.57	$0.40	$0.51
(13)	Total Facilities Investment Costs (9) + (12)		$44.27	$31.41	$22.96	$36.88	$15.45	$40.75	$31.27	$37.51
(14)	Total Annual Marginal Cost per kw		**$44.27**	**$31.41**	**$22.96**	**$36.88**	**$15.45**	**$40.75**	**$31.27**	**$37.51**

1/ Schedule 5, page 1
2/ Schedule 14
3/ Schedule 13
4/ Schedule 14
5/ Schedule 5, page 2
6/ Schedule 14
7/ Schedule 14
8/ Schedule 14

SCHEDULE 11

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Computation of Customer Related Marginal Unit Costs
(2010 Dollars)

		Residential	Commercial				Industrial		Irrigation	Metered Lighting	Unmetered General
		Rate 01	Rate 07	Rate 09 - P	Rate 09 - S	Rate 09 - T	Rate 19	Rate 19 - T	Rate 24	Rates 41,42	Rate 40
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
(1) Meter Investment	1/	$378.00	$429.00	$10,024.00	$666.00	$10,024.00	$13,276.00	$13,276.00	$424.00	$375.00	$0.00
(2) Service Drop	2/	$254.00	$285.00	$0.00	$319.00	$0.00	$0.00	$0.00	$324.00	$259.46	$0.00
(3) With General Plant Loading((1) + (2)) x 1.08	3/	$683.37	$772.04	$10,838.78	$1,065.06	$10,838.78	$14,355.11	$14,355.11	$808.80	$686.03	$0.00
(4)											
(5) Annual Economic Charge Related to											
(6) Capital Investment	4/	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%
(7) A&G Loading (Plant Related)	5/	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
(8) Total (5) + (7)		7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
(9)											
(10) Annualized Costs (3) x (8)		$48.50	$54.79	$769.18	$75.58	$769.18	$1,018.72	$1,018.72	$57.40	$48.68	$0.00
(11)											
(12) Meter O&M Expense	6/	$14.33	$16.18	$379.30	$25.26	$379.30	$502.33	$502.33	$16.03	$14.19	$0.00
(13) Customer Accounts Expenses	7/	$39.50	$39.50	$39.50	$39.50	$39.50	$553.00	$553.00	$39.50	$39.50	$39.50
(14) Customer Service and Informational Expenses	8/	$14.90	$14.90	$14.90	$14.90	$14.90	$14.90	$14.90	$14.90	$14.90	$14.90
(15) With A&G Loading [(12)+(13)+(14)] x 1.399	9/	96.14	98.72	606.64	111.43	606.64	1496.99	1496.99	98.51	95.94	76.09
(16) (Non-Plant Related)											
(17)											
(18) Customer Related Cost (10) + (15)		$144.63	$153.51	$1,375.83	$187.01	$1,375.83	$2,515.72	$2,515.72	$155.91	$144.63	$76.09
(19)											
(20) Working Capital											
(21) Materials and Supplies (3) x 1.14%	10/	$7.76	$8.77	$123.15	$12.10	$123.15	$163.10	$163.10	$9.19	$7.79	$0.00
(22) Revenue Requirement for Working Capital											
(23) [(21) x 11.62%	11/	$0.90	$1.02	$14.31	$1.41	$14.31	$18.95	$18.95	$1.07	$0.91	$0.00
(24)											
(25) Total Customer Related Costs (18) + (23)		$145.53	$154.53	$1,390.14	$188.41	$1,390.14	$2,534.67	$2,534.67	$156.98	$145.53	$76.09
(26)											
(27) Total Annual Marginal Unit Cost		**$145.53**	**$154.53**	**$1,390.14**	**$188.41**	**$1,390.14**	**$2,534.67**	**$2,534.67**	**$156.98**	**$145.53**	**$76.09**

1/ Schedule 6, Page 1
2/ Schedule 7
3/ Schedule 14
4/ Schedule 13
5/ Schedule 14
6/ Schedule 6, Page 2
7/ Schedule 8, Page 1
8/ Schedule 9
9/ Schedule 14
10/ Schedule 14
11/ Schedule 14

SCHEDULE 12

SCHEDULE 13

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Economic Carrying Charges

(1)	Combustion Turbine	7.18%
(2)	Transmission	6.12%
(3)	Distribution Substation	6.57%
(4)	Distribution Facilities	6.57%
(5)	Meters	6.57%

SCHEDULE 14

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Summary of Loaders

General Plant Loading	1.08
A&G Loading	
Plant-Related	0.53%
Non-Plant Related	1.399
Revenue Requirement for Working Capital & Fuel Inventory	11.62%
Materials and Supplies	1.14%

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Loss Factors

DEMAND

Plant from	Served at: Trans-mission	Primary	Secondary
Generation & Transmission	1.055	1.100	1.130
Distribution Substation	-----	1.043	1.071
Primary	-----	1.033	1.061
Secondary	-----	-----	1.027

ENERGY

Plant from	Served at: Trans-mission	Distribution Station	Primary	Secondary
Generation	1.035	1.050	1.074	1.109

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Marginal Unit Cost By Class
(2010 Dollars)

Description	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
Demand Related Marginal Unit Cost												
Generation ($/Peak kW)												
January	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
February	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
March	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
April	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
June	$8.44	$8.44	$8.44	$8.44	$8.44	$8.44	$8.44	$8.44	$8.44	$8.44	$8.44	$8.44
July	$11.51	$11.51	$11.51	$11.51	$11.51	$11.51	$11.51	$11.51	$11.51	$11.51	$11.51	$11.51
August	$3.47	$3.47	$3.47	$3.47	$3.47	$3.47	$3.47	$3.47	$3.47	$3.47	$3.47	$3.47
September	$12.71	$12.71	$12.71	$12.71	$12.71	$12.71	$12.71	$12.71	$12.71	$12.71	$12.71	$12.71
October	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
November	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
December	$1.87	$1.87	$1.87	$1.87	$1.87	$1.87	$1.87	$1.87	$1.87	$1.87	$1.87	$1.87
Total	$38.00	$38.00	$38.00	$38.00	$38.00	$38.00	$38.00	$38.00	$38.00	$38.00	$38.00	$38.00
Transmission ($/Peak kW)												
January	$6.89	$6.89	$6.89	$6.89	$6.89	$6.89	$6.89	$6.89	$6.89	$6.89	$6.89	$6.89
February	$4.90	$4.90	$4.90	$4.90	$4.90	$4.90	$4.90	$4.90	$4.90	$4.90	$4.90	$4.90
March	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75
April	$3.67	$3.67	$3.67	$3.67	$3.67	$3.67	$3.67	$3.67	$3.67	$3.67	$3.67	$3.67
May	$13.05	$13.05	$13.05	$13.05	$13.05	$13.05	$13.05	$13.05	$13.05	$13.05	$13.05	$13.05
June	$23.22	$23.22	$23.22	$23.22	$23.22	$23.22	$23.22	$23.22	$23.22	$23.22	$23.22	$23.22
July	$26.24	$26.24	$26.24	$26.24	$26.24	$26.24	$26.24	$26.24	$26.24	$26.24	$26.24	$26.24
August	$19.91	$19.91	$19.91	$19.91	$19.91	$19.91	$19.91	$19.91	$19.91	$19.91	$19.91	$19.91
September	$20.85	$20.85	$20.85	$20.85	$20.85	$20.85	$20.85	$20.85	$20.85	$20.85	$20.85	$20.85
October	$8.63	$8.63	$8.63	$8.63	$8.63	$8.63	$8.63	$8.63	$8.63	$8.63	$8.63	$8.63
November	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75
December	$9.14	$9.14	$9.14	$9.14	$9.14	$9.14	$9.14	$9.14	$9.14	$9.14	$9.14	$9.14
Total	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00
Distribution												
Distribution Substation ($/Peak kW)	$11.00	$11.00	$11.00	$11.00	$0.00	$11.00	$11.00	$0.00	$11.00	$11.00	$11.00	$11.00
Distribution Facilities Investment ($/Peak kW)	$44.27	$31.41	$36.88	$22.96	$0.00	$31.27	$15.45	$0.00	$40.75	$37.51	$31.27	$31.27
Energy Related Marginal Unit Cost												
Generation Energy Related ($/MWh)												
January	$38.65	$38.65	$38.65	$38.65	$38.65	$38.65	$38.65	$38.65	$38.65	$38.65	$38.65	$38.65
February	$35.92	$35.92	$35.92	$35.92	$35.92	$35.92	$35.92	$35.92	$35.92	$35.92	$35.92	$35.92
March	$34.52	$34.52	$34.52	$34.52	$34.52	$34.52	$34.52	$34.52	$34.52	$34.52	$34.52	$34.52
April	$32.10	$32.10	$32.10	$32.10	$32.10	$32.10	$32.10	$32.10	$32.10	$32.10	$32.10	$32.10
May	$32.93	$32.93	$32.93	$32.93	$32.93	$32.93	$32.93	$32.93	$32.93	$32.93	$32.93	$32.93
June	$30.21	$30.21	$30.21	$30.21	$30.21	$30.21	$30.21	$30.21	$30.21	$30.21	$30.21	$30.21
July	$46.12	$46.12	$46.12	$46.12	$46.12	$46.12	$46.12	$46.12	$46.12	$46.12	$46.12	$46.12
August	$46.66	$46.66	$46.66	$46.66	$46.66	$46.66	$46.66	$46.66	$46.66	$46.66	$46.66	$46.66
September	$43.13	$43.13	$43.13	$43.13	$43.13	$43.13	$43.13	$43.13	$43.13	$43.13	$43.13	$43.13
October	$43.68	$43.68	$43.68	$43.68	$43.68	$43.68	$43.68	$43.68	$43.68	$43.68	$43.68	$43.68
November	$44.72	$44.72	$44.72	$44.72	$44.72	$44.72	$44.72	$44.72	$44.72	$44.72	$44.72	$44.72
December	$49.59	$49.59	$49.59	$49.59	$49.59	$49.59	$49.59	$49.59	$49.59	$49.59	$49.59	$49.59
Customer Related Marginal Unit Cost ($/Cust.)	$145.53	$154.53	$188.41	$1,390.14	$1,390.14	$0.00	$2,534.67	$2,534.67	$156.98	$76.09	$145.53	$145.53

SCHEDULE 16

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Matthew T. Larkin
Summary of Marginal Costs by Customer Class

July 29, 2011

IDAHO POWER COMPANY
Marginal Cost Analysis 2011
Marginal Cost By Class - OREGON JURISDICTION
(2010 Dollars)

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(I) LG POWER PRIMARY (19-P)	(J) LG POWER TRANS (19-T)	(K) IRRIGATION SECONDARY (24-S)	(L) UNMETERED GEN SERVICE (40)	(M) MUNICIPAL ST LIGHT (41)	(N) TRAFFIC CONTROL (42)
1														
2	Current Revenue	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	Demand Related Marginal Cost													
5														
6	Generation	$4,419,781	$1,632,977	$107,217	$668,471	$83,125	$14,170	$250	$716,166	$593,487	$603,360	$63	$414	$80
7	Transmission	$16,576,157	$6,144,722	$436,496	$2,812,421	$346,543	$54,799	$2,265	$3,020,567	$1,897,509	$1,856,542	$250	$3,727	$316
8	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
9														
10	Energy Related Marginal Cost													
11	Generation Energy Related	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
12														
13	Customer Related Marginal Cost	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
14														
15	Total Functionalized Revenue Requirement													
16	Generation													
17	Demand-Related	$10,427,415	$3,852,618	$252,954	$1,577,097	$196,114	$33,431	$591	$1,689,621	$1,400,191	$1,423,483	$149	$977	$189
18	Energy-Related	$15,370,848	$4,813,964	$432,072	$2,767,706	$349,938	$63,397	$11,513	$4,125,532	$1,667,777	$1,119,722	$307	$18,530	$389
19														
20	Transmission	$4,573,960	$1,695,551	$120,445	$776,049	$95,624	$15,121	$625	$833,483	$523,591	$512,287	$69	$1,028	$87
21														
22	Distribution													
23	Demand-Related	$11,661,526	$5,398,087	$304,285	$2,216,157	$169,212	$0	$9,634	$1,341,411	$0	$2,206,620	$271	$15,698	$150
24	Customer-Related													
25	Allocated	$3,249,479	$2,278,084	$446,524	$205,456	$7,781	$1,610	$0	$17,612	$2,935	$286,010	$264	$2,191	$1,011
26	Direct Assignment	$438,190	$196,738	$35,868	$12,919	$72	$14	$82,755	$87	$14	$22,919	$43	$86,672	$87
27														
28	Total	$45,721,417	$18,235,041	$1,592,149	$7,555,385	$818,741	$113,574	$105,118	$8,007,747	$3,594,509	$5,571,041	$1,104	$125,096	$1,913
29														
30	Revenue Deficiency	$5,847,826	$2,879,109	$32,749	$579,470	$20,639	($41,423)	($7,344)	($205,318)	$471,116	$2,116,770	$132	$1,245	$682
31														
32	% Increase Required	14.67%	18.75%	2.10%	8.31%	2.59%	-26.72%	-6.53%	-2.50%	15.08%	61.28%	13.57%	1.01%	55.42%
33														

Idaho Power Company
Marginal Cost Analysis 2011
2011 TY Revenue Requirement per Billing Component - OREGON JURISDICTION

**** * * RESIDENTIAL SERVICE - SCHEDULE 1 * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KWH)	(E) NON-SUMMER ($/KWH)	(F) SERVICE ($/CUST/MO)
GENERATION						
DEMAND - Summer	$2,543,378.98	48,317,247	0.05264	0.05264		
DEMAND - Non-Summer	$1,309,238.67	150,525,172	0.00870		0.00870	
ENERGY - Summer	$1,115,735.22	48,317,247	0.02309	0.02309		
ENERGY - Non-Summer	$3,698,228.81	150,525,172	0.02457		0.02457	
TRANSMISSION						
DEMAND	$1,695,550.60	198,842,419	0.00853	0.00853	0.00853	
DISTRIBUTION	$5,398,086.74	198,842,419	0.02715	0.02715	0.02715	
CUSTOMERS (BILLINGS)	$2,474,821.53	162,935	15.18904			15.18904
TOTALS	$18,235,040.56			0.11141	0.06894	15.18904

**** * * SMALL GENERAL SERVICE - SCHEDULE 7 * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KWH)	(E) NON-SUMMER ($/KWH)	(F) SERVICE ($/CUST/MO)
GENERATION						
DEMAND - Summer	$166,292.62	4,398,313	0.03781	0.03781		
DEMAND - Non-Summer	$86,661.19	13,444,583	0.00645		0.00645	
ENERGY - Summer	$110,504.34	4,398,313	0.02512	0.02512		
ENERGY - Non-Summer	$321,568.04	13,444,583	0.02392		0.02392	
TRANSMISSION						
DEMAND	$120,444.98	17,842,896	0.00675	0.00675	0.00675	
DISTRIBUTION	$304,285.42	17,842,896	0.01705	0.01705	0.01705	
CUSTOMERS (BILLINGS)	$482,391.94	29,705	16.23931			16.23931
TOTALS	$1,592,148.52			0.08674	0.05417	16.23931

*** * * LARGE GENERAL SERVICE - SCHEDULE 9 SECONDARY * * ***

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(I) SERVICE ($/CUST/MO)	(H) BASIC ($/KW)
GENERATION									
DEMAND - Summer	$991,423.14	82,732	11.98351	11.98351					
DEMAND - Non-Summer	$585,673.72	280,625	2.08704		2.08704				
ENERGY - Summer	$643,032.58	25,642,384	0.02508			0.02508			
ENERGY - Non-Summer	$2,124,673.60	88,613,835	0.02398				0.02398		
TRANSMISSION									
DEMAND	$776,048.50	363,357	2.13577	2.13577	2.13577				
DISTRIBUTION	$2,216,157.28	505,535	4.38378						4.38378
CUSTOMERS (BILLINGS)	$218,375.69	10,700	20.40951					20.40951	
TOTALS	$7,555,384.52			14.11928	4.22281	0.02508	0.02398	20.40951	4.38378

*** * * LARGE GENERAL SERVICE - SCHEDULE 9 PRIMARY * * ***

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(I) SERVICE ($/CUST/MO)	(H) BASIC ($/KW)
GENERATION									
DEMAND - Summer	$126,927.53	8,596	14.76656	14.76656					
DEMAND - Non-Summer	$69,186.44	26,370	2.62364		2.62364				
ENERGY - Summer	$87,182.37	3,649,404	0.02389			0.02389			
ENERGY - Non-Summer	$262,755.46	11,449,684	0.02295				0.02295		
TRANSMISSION									
DEMAND	$95,623.67	34,966	2.73476	2.73476	2.73476				
DISTRIBUTION	$169,212.06	44,344	3.81590						3.81590
CUSTOMERS (BILLINGS)	$7,853.65	60	130.89409					130.89409	
TOTALS	$818,741.17			17.50132	5.35840	0.02389	0.02295	130.89409	3.81590

**** * * LARGE GENERAL SERVICE - SCHEDULE 9 TRANSMISSION * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(I) SERVICE ($/CUST/MO)
GENERATION								
DEMAND - Summer	$18,492.20	3,114	5.93784	5.93784				
DEMAND - Non-Summer	$14,939.19	8,667	1.72362		1.72362			
ENERGY - Summer	$15,438.05	640,108	0.02412			0.02412		
ENERGY - Non-Summer	$47,959.26	2,192,401	0.02188				0.02188	
TRANSMISSION								
DEMAND	$15,121.02	11,782	1.28344	1.28344	1.28344			
CUSTOMERS (BILLINGS)	$1,624.39	12	135.36604					135.36604
TOTALS	$113,574.11			7.22128	3.00707	0.02412	0.02188	135.36604

**** * * LARGE POWER - SCHEDULE 19 PRIMARY * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(I) SERVICE ($/CUST/MO)	(H) BASIC ($/KW)
GENERATION									
DEMAND - Summer	$1,156,690.26	82,590	14.00519	14.00519					
DEMAND - Non-Summer	$532,931.00	246,450	2.16243		2.16243				
ENERGY - Summer	$1,043,985.71	44,170,902	0.02364			0.02364			
ENERGY - Non-Summer	$3,081,546.79	135,018,145	0.02282				0.02282		
TRANSMISSION									
DEMAND	$833,483.39	329,040	2.53308	2.53308	2.53308				
DISTRIBUTION	$1,341,410.53	358,346	3.74334						3.74334
CUSTOMERS (BILLINGS)	$17,699.15	72	245.82147					245.82147	
TOTALS	$8,007,746.83			16.53827	4.69551	0.02364	0.02282	245.82147	3.74334

*** * * LARGE POWER - SCHEDULE 19 TRANSMISSION * * ***

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(I) SERVICE ($/CUST/MO)
GENERATION								
DEMAND - Summer	$890,030.82	52,429	16.97579	16.97579				
DEMAND - Non-Summer	$510,160.68	100,121	5.09546		5.09546			
ENERGY - Summer	$652,825.24	28,508,164	0.02290			0.02290		
ENERGY - Non-Summer	$1,014,951.41	45,647,703	0.02223				0.02223	
TRANSMISSION								
DEMAND	$523,591.26	152,550	3.43226	3.43226	3.43226			
CUSTOMERS (BILLINGS)	$2,949.86	12	245.82147					245.82147
TOTALS	$3,594,509.26			20.40805	8.52772	0.02290	0.02223	245.82147

*** * * IRRIGATION - SCHEDULE 24 SECONDARY * * ***

(Production-related revenue and billing units are for June - September)

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) IN-SEASON ($/KW)	(E) OUT-SEASON ($/KW)	(F) IN-SEASON ($/KWH)	(G) OUT-SEASON ($/KWH)	(H) SERVICE ($/CUST/MO)
GENERATION								
DEMAND - In-Season	$1,423,140.88	106,958	13.30555	13.30555				
DEMAND - Out-Season	$341.86	33,431	0.01023		0.01023			
ENERGY - In-Season	$909,502.53	39,590,985	0.02297			0.02297		
ENERGY - Out-Season	$210,219.81	7,058,280	0.02978				0.02978	
TRANSMISSION								
DEMAND	$512,286.99	140,390	3.64904	3.64904	3.64904			
DISTRIBUTION	$2,206,620.42	140,390	15.71783	15.71783	15.71783			
CUSTOMERS (BILLINGS)	$308,928.54	18,981	16.27576					16.27576
TOTALS	$5,571,041.03			32.67242	19.37710	0.02297	0.02978	16.27576

Idaho Power/1007
Witness: Matthew T. Larkin

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Matthew T. Larkin
Revenue Allocation Summary

July 29, 2011

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2011
Proformed Normalized Sales and Revenue

Line No.	Tariff Description	Rate Schedule No.	2011 Average Number of Customers	2011 Sales Normalized (kWh)	Proformed Normalized Revenue	Average Mills per kWh
	Uniform Tariff Schedules					
1	Residential Service	1	13,578	198,842,419	$ 15,355,932	77.23
2	Small General Service	7	2,475	17,842,896	1,559,400	87.40
3	Large General Service	9-S	892	114,256,219	6,975,915	61.06
4	Large General Service	9-P	5	15,099,088	798,102	52.86
5	Large General Service	9-T	1	2,832,509	154,997	54.72
6	Dusk/Dawn Lighting	15	-	483,936	112,462	232.39
7	Large Power Service	19-P	6	179,189,047	8,213,065	45.83
8	Large Power Service	19-T	1	74,155,867	3,123,393	42.12
9	Irrigation Service	24	1,582	46,649,265	3,454,271	74.05
10	Unmetered Service	40	3	12,900	972	75.35
11	Municipal Street Lighting	41	14	778,108	123,851	159.17
12	Traffic Control Lighting	42	6	16,328	1,231	75.39
13	*Total Oregon Rates*		18,563	650,158,582	39,873,591	61.33

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2011
Marginal Cost - Revenue Allocation Results

Line No.	Tariff Description	Rate Schedule No.	COS Percent Change	COS Revenue Change	Revenue Allocation at COS	Average Mills per kWh
	Uniform Tariff Schedules					
1	Residential Service	1	18.75%	$ 2,879,109	$ 18,235,041	91.71
2	Small General Service	7	2.10%	$ 32,749	$ 1,592,149	89.23
3	Large General Service	9-S	8.31%	$ 579,470	$ 7,555,385	66.13
4	Large General Service	9-P	2.59%	$ 20,639	$ 818,741	54.22
5	Large General Service	9-T	-26.72%	$ (41,423)	$ 113,574	40.10
6	Dusk/Dawn Lighting	15	-6.53%	$ (7,344)	$ 105,118	217.21
7	Large Power Service	19-P	-2.50%	$ (205,318)	$ 8,007,747	44.69
8	Large Power Service	19-T	15.08%	$ 471,116	$ 3,594,509	48.47
9	Irrigation Service	24	61.28%	$ 2,116,770	$ 5,571,041	119.42
10	Unmetered Service	40	13.57%	$ 132	$ 1,104	85.58
11	Municipal Street Lighting	41	1.01%	$ 1,245	$ 125,096	160.77
12	Traffic Control Lighting	42	55.42%	$ 682	$ 1,913	117.17
13	*Total Oregon Rates*		14.67%	$ 5,847,826	45,721,417	70.32

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2011
First Pass Revenue Allocation

Line No.	Tariff Description	Rate Schedule No.	First Pass Percent Change	First Pass Revenue Change	First Pass Revenue Allocation
	Uniform Tariff Schedules				
1	Residential Service	1	18.75%	$ 2,879,109	$ 18,235,041
2	Small General Service	7	2.10%	32,749	$ 1,592,149
3	Large General Service	9-S	8.31%	579,470	$ 7,555,385
4	Large General Service	9-P	2.59%	20,639	$ 818,741
5	Large General Service	9-T	0.00%	0	$ 154,997
6	Dusk/Dawn Lighting	15	0.00%	0	$ 112,462
7	Large Power Service	19-P	0.00%	0	$ 8,213,065
8	Large Power Service	19-T	15.08%	471,116	$ 3,594,509
9	Irrigation Service	24	29.34%	1,013,483	$ 4,467,754
10	Unmetered Service	40	13.57%	132	$ 1,104
11	Municipal Street Lighting	41	1.01%	1,245	$ 125,096
12	Traffic Control Lighting	42	29.34%	361	$ 1,592
13	*Total Oregon Rates*		11.14%	4,998,303	44,871,894
14					
15					
16	Revenue Requirement Shortfall				$ 849,523

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2011
Final Revenue Allocation

Line No.	Tariff Description	Rate Schedule No.	Final Percent Change	Final Revenue Change	Final Revenue Allocation	Average Mills per kWh	Cost of Service Index
	Uniform Tariff Schedules						
1	Residential Service	1	21.91%	$ 3,364,387.39	$ 18,720,319	94.15	103%
2	Small General Service	7	4.82%	$ 75,119.47	$ 1,634,519	91.61	103%
3	Large General Service	9-S	11.19%	$ 780,536.70	$ 7,756,452	67.89	103%
4	Large General Service	9-P	5.32%	$ 42,427.86	$ 840,530	55.67	103%
5	Large General Service	9-T	0.00%	$ -	$ 154,997	54.72	136%
6	Dusk/Dawn Lighting	15	0.00%	$ -	$ 112,462	232.39	107%
7	Large Power Service	19-P	0.00%	$ -	$ 8,213,065	45.83	103%
8	Large Power Service	19-T	18.15%	$ 566,774.90	$ 3,690,168	49.76	103%
9	Irrigation Service	24	29.34%	$ 1,013,483.11	$ 4,467,754	95.77	80%
10	Unmetered Service	40	16.60%	$ 161.31	$ 1,133	87.85	103%
11	Municipal Street Lighting	41	3.69%	$ 4,574.22	$ 128,425	165.05	103%
12	Traffic Control Lighting	42	29.34%	$ 361.18	$ 1,592	97.51	83%
13	*Total Oregon Rates*		14.67%	5,847,826	45,721,417	70.32	100%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF OREGON.	)))))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DARLENE NEMNICH

July 29, 2011

Q. Please state your name and business address.

A. My name is Darlene Nemnich. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

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

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Senior Regulatory Analyst.

Q. Please describe your educational background.

A. In May of 1979, I received a Bachelor of Arts degree in Business Administration with emphases in Finance and Economics from the College of Idaho. In addition, I have attended the electric utility ratemaking course offered through New Mexico State University's Center for Public Utilities as well as various other ratemaking courses sponsored by the Edison Electric Institute. I am also an active member of the Edison Electrical Institute's Rate and Regulatory Analysts Group.

Q. Please describe your work experience with Idaho Power.

A. In 1982, I was hired as an analyst in the Resource Planning Department. My primary duties were the calculation of avoided costs for cogeneration and small power production contracts and the calculation of costs of future generation resource options. In 1989, I moved to the Energy Services Department where I performed economic, financial, and statistical analyses to determine the cost-effectiveness of demand-side management programs. I stayed in that general area designing, implementing, and evaluating programs until 2000, when I was promoted to Energy Efficiency Coordinator. In that capacity, I coordinated the Company's effort to grow customer programs and education in energy efficiency promotion. I was responsible for ensuring Company compliance with regulatory and financial requirements in the area of energy efficiency. In 2003, I was promoted to Energy Efficiency Leader where I managed the Company's demand-side management effort, including strategic planning, design and development of programs, regulatory compliance, and overall management of the department. In 2006, I left the Company to pursue personal opportunities. In April 2008, I returned to the Company as a Senior Regulatory Analyst in the Regulatory Affairs Department. My duties as Senior Regulatory Analyst include the development of alternative pricing structures, analysis of the impact on customers of rate design changes, and the administration of the Company's tariffs. I have testified before the Commission and the Idaho Public Utility Commission several times.

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

A. My testimony will address the Company's rate design proposal for the residential customer class.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits relating to residential rate design:

- Exhibit 1101 - Calculation of Revenue Impact
- Exhibit 1102 - Typical Monthly Billing Comparison

I. RESIDENTIAL RATE DESIGN OBJECTIVES

Q. What are the Company's overall objectives with regard to its rate design strategy?

A. The Company's rate design is developed to recover the revenue requirement targets provided by Mr. Matthew T. Larkin for each customer class. In doing so, the Company continues to maintain two important objectives with regard to rate design: (1) to establish prices that primarily reflect the costs of the services provided; and (2) to present cost-based rate proposals designed to align with and encourage energy efficiency.

Q. Does the Company's proposed residential rate design establish prices that primarily reflect the costs of services provided?

A. Yes. This proposal establishes rates that recover the target revenue described by Mr. Larkin, and also implements the Company's rate design objectives by pricing the individual rate components closer to the unit costs of providing electric service. To further address the Company's rate design objectives, I am also proposing the implementation of a two-tiered inverted block seasonal rate design with modified energy rate block levels.

Q. Does your proposal encourage increased energy efficiency?

A. Yes. My proposal supports the continuation of tiered rates and the implementation of seasonal rates, both of which encourage customers to use energy more efficiently in response to the appropriate price signals.

Q. Please describe the methodology used to move current rate levels closer to cost-of-service levels for Schedule 1.

A. The methodology used to calculate the proposed rate component adjustments for Schedule 1 represents a uniform percentage movement of 5 percent toward the unit cost-of-service intended for recovery by that rate component. In applying this methodology, the Company first considered the percentage of overall revenue that would be recovered under each Schedule 1 billing component if each billing component was set at the full unit cost-of-service. These percentages established the target revenue for each billing component. Second, the Company determined the percentage of overall revenue currently recovered by each billing component at existing base rates. The difference, or gap, between the targeted level and the actual percentage was then determined for each billing component. The current percentage of overall revenue by billing component was then adjusted by approximately 5 percent of the gap to establish adjusted revenue targets.

Q. Did the Company consider increasing all Schedule 1 rate components on a uniform percentage basis?

A. No. If all billing components were increased by the same uniform percentage without consideration of the cost-of-service unit costs, then some billing units would move further away from their actual unit cost-of-service, contrary to the Company's objective of moving toward cost-based rate designs. Moving all billing components 5 percent closer to their respective cost-of-service unit cost provides a reasonable, quantifiable goal while meeting the Company's first rate design objective of establishing prices that primarily reflect the costs of the services provided.

Q. **Is the methodology described above the only way you have modified rate levels to accomplish the Company's stated goals?**

A. No. To provide better pricing signals in the movement towards the cost-of-service goal, Idaho Power is also proposing to raise the tier block cut-off levels and to implement seasonal rates. These proposals are described in greater detail later in my testimony.

II. <u>RESIDENTIAL RATE DEVELOPMENT</u>

Q. What is the annual revenue requirement to be recovered from Residential Service customers taking service under Schedule 1?

A. The annual revenue to be recovered from Residential Service customers taking service under Schedule 1 is $18,720,319, as shown in Mr. Larkin's Exhibit 1007, page 4. This number represents an overall increase for the residential class of 21.91 percent.

Q. Please describe the present rate structure for Residential Service under Schedule 1.

A. Residential Service customers currently taking service under Schedule 1 pay a monthly Service Charge of $8.00. Their Energy Charge is based upon a two-tier inverted block structure in which they pay a base rate of 6.0253 cents per kilowatt-hour ("kWh") for the first 300 kWh of energy used (the first block) and 7.3884 cents per kWh for all energy used over 300 kWh (the second block).

Q. Please describe the Company's proposal to increase the Service Charge.

A. The Service Charge is intended to recover costs that do not vary with the amount of energy or capacity used. This includes the investments in the service line and meter as well as billing costs. Historically, the Service Charge has been well below the cost-of-service unit cost, meaning that the Service Charge, from a cost-of-service standpoint, has under-collected the customer-related fixed costs associated with this rate component. Consistent with the Company's rate design objective to move the individual rate components closer to the cost-of-service unit costs, the Company is proposing to increase the Service Charge to $10.00 per customer per month.

Q. How does the proposed $10.00 Service Charge compare with the cost-of-service results?

A. The $10.00 per month Service Charge represents approximately 66 percent of the cost-of-service unit cost result of $15.19 shown at line 24 on page 2 of Mr. Larkin's Exhibit 1006. The calculation of moving the Service Charge level 5 percent closer to cost-of-service levels resulted in a $10.03 amount. The Company rounded this value to $10.00.

Q. Are there other reasons to increase the Service Charge?

A. Yes. In addition to meeting the Company's objective of moving rate components closer to the cost-of-service, increasing the Service Charge also helps remove the inherent financial disincentive for an electric utility to invest in energy efficiency programs by reducing the amount of fixed costs that would be recovered through the volumetric energy charge.

Q. Please describe your proposal to modify the Energy Charge block levels.

A. Currently, customers taking service under Schedule 1 pay one rate for the first 300 kWh of energy used and a slightly higher rate for all energy used over 300 kWh year-round. The Company is proposing to raise the cut-off for the first block of energy usage to 1,000 kWh.

Q. Why are you proposing to raise the size of the first block of energy use?

A. Inverted block rates are a mechanism for providing an incentive to customers to conserve energy by charging customers a higher rate for energy as the amount of energy usage increases. One of the Company's goals for the first energy block is to set it at a level that will cover a majority of customers' basic electric usage, or the usage that customers may not be able to reduce, for example usage from lighting and home appliances. Usage that falls in the second block, which is priced at a higher rate, is more likely discretionary usage. The Company has found that basic electric usage generally consists of more than 300 kWh per month, the current level of the first block.

Q. How did you determine that 1,000 kWh per month is the appropriate amount for the first block of energy usage?

A. Idaho Power conducted a bill frequency analysis of all residential usage in 2010. This analysis showed that on an annual basis, approximately 52.4 percent of all bills were for 1,000 kWh or less, representing approximately 64 percent of all kWh usage for the year. Idaho Power proposes a first-tier cut-off level of 1,000 kWh in order to provide a price signal to conserve to the highest 36 percent of usage.

In addition, Idaho Power examined customers' loads during the spring and fall months, a time when it is reasonable to assume that neither an air conditioner nor a heater would be running or, if running, would have minimal usage. This would likely occur in May and October. The 2010 average usage for May and October was 923 kWh and 821 kWh, respectively. This baseline load estimate would probably include a customer's lighting, basic home appliances (a refrigerator, range, oven, microwave, and water heater) as well as other household appliances, such as clocks, stereos/radios, telephones, vacuum cleaners, televisions, and clothes washers and dryers. Idaho Power's proposed block level of 1,000 kWh would provide the lower, first block rates for all typical baseline usage.

Also, Idaho Power examined the average monthly residential customer energy usage. In the Company's Oregon jurisdiction, the 5-year average normalized energy usage through 2010 is 1,233 kWh per month. In an effort to incent customers to conserve year-round, the Company is proposing to set the first block at approximately 80 percent of the average monthly energy usage for the Company's customers in Oregon, or 1,000 kWh. Furthermore, adjusting the first consumption tier to 1,000 kWh will allow a large percentage of what might be considered basic electric usage to be priced at the lower rate.

Q. How does your proposal of the first block cut-off at 1,000 kWh compare with the first block cut-off of other utilities' residential rates in Oregon?

A. Both Portland General Electric and Pacific Power have two-tiered inverted block rates for their residential customers in Oregon. And for both utilities, the cut-off for the first-tier is 1,000 kWh.

Q. Why is the Company proposing to add a seasonal component to the existing two-tier rate structure?

A. Idaho Power continues to be a summer peaking utility with its highest system peak occurring during the summer months. The unit costs resulting from the Company's proposed cost-of-service study indicate that the residential kilowatt-hour unit cost is approximately 61 percent higher in the summer than for the non-summer months. In fact, the unit cost differential for the generation function alone, as provided by the marginal cost allocation methodology described by Mr. Larkin, results in a summer differential of more than 127 percent over the non-summer months. The current residential rate design, which does not include a seasonal component, does not provide customers with any indication that the costs incurred by the Company to provide them energy service during the three summer months are significantly greater than the nine non-summer months. In addition, the Company's Oregon residential rate design is the only rate design in all of the Company's other major rate designs in both Idaho and Oregon that does not have a seasonal pricing component. All of the other rate designs provide customers with a seasonal pricing signal. It is appropriate to send a higher price signal to encourage customers to use energy more efficiently during the summer peak months.

Q. How are the seasons defined for the Company's residential pricing proposal?

A. For the Energy Charge rate components, the Company is proposing seasonal rates for two seasons, summer and non-summer. The summer season is defined as June 1 through August 31. The non-summer season is defined as September 1 through May 31. The proposed seasonal definition for the residential class is the same as that currently in place for Schedule 7, Schedule 9, and Schedule 19 customers within Oregon as well as what is in place for Schedule 1, Schedule 7, Schedule 9, and Schedule 19 customers throughout the Company's Idaho service territory.

Q. Please describe the Company's proposal for applying seasonal rates to the Energy Charge.

A. For the summer months, the rate proposed for the first block Energy Charge is 8.2222 cents per kWh and 10.0310 cents per kWh for the second block Energy Charge. During the non-summer months, the proposed rates for the first and second Energy Charge blocks are 8.2222 cents per kWh and 9.1266 cents per kWh, respectively. This results in a first block Energy Charge rate of 8.2222 cents per kWh for all months of the year. There will be a difference in the rates only in the second block from summer season to non-summer season. Customers whose usage falls within that first block every month will not see a seasonal difference in rates; rather, they will pay the same Energy Charge rate year-round. Only those customers who use more than 1,000 kWh per month and whose usage moves into the second tier will receive a seasonal price signal. This proposed rate design is shown on page 1 of Exhibit 1101.

When an average seasonal rate is calculated with these proposed rates, and compared to each other, a seasonal differential of approximately 1.5 percent results. This moderate seasonal differential sends an introductory price signal to customers as a step towards seasonal rates.

Q. Why is the Company proposing first block Energy Charge rates at the same level for both seasons?

A. As indicated earlier in this testimony, electric usage that falls in the first block is less likely to be discretionary usage where customers may have less ability to respond to price signals. Setting the first block Energy Charges the same year-round recognizes this limitation. Currently, customers experience the same Energy Charge rate year-round for the first 300 kWh of usage. With Idaho Power's proposal, customers will experience the same Energy Charge rate year-round for the first 1,000 kWh of usage.

Q. What are the differentials between the first and second block in the summer season as compared to the non-summer season?

A. For the summer season rates, Idaho Power's proposes no change to the differential between first block and second block – it remains at the current differential of approximately 22 percent. For the non-summer season, Idaho Power proposes a smaller differential of only 11 percent.

Q. Why would the block differential in the summer be larger than the block differential for the non-summer rates?

A. As shown in Mr. Larkin's Exhibit 1006 on page 2, and discussed on page 7 above, the summer season cost-of-service unit costs for energy are much higher than the non-summer season cost-of-service unit costs for energy. Setting the differential higher in the summer than winter is the mechanism to send this cost-based price signal to customers.

III. RESIDENTIAL RATE PROPOSAL SUMMARY

Q. Please summarize the Company's rate design proposal for Schedule 1.

A. The Company proposes that the Service Charge be set at $10.00 per month. During the summer season, the Company proposes customers pay a base Energy Charge of 8.2222 cents per kWh for the first 1,000 kWh of energy used and 10.0310 cents per kWh for all additional kWh over 1,000 each month. During the non-summer season, the Company proposes customers pay an Energy Charge of 8.2222 cents per kWh for the first 1,000 kWh of energy used and 9.1266 cents per kWh for all additional kWh over 1,000 each month.

The Company's proposed rate design for Schedule 1, Residential Service, is shown on page 1 of Exhibit 1101.

Q. What impact will this rate design proposal have on Residential Service customers taking service under Schedule 1?

A. The typical monthly billing comparison for Residential Service customers taking service under Schedule 1 appears on page one of Exhibit 1102. This comparison shows that given the typical monthly usage blocks shown in Exhibit 1102, the range of increase is from 32.94 percent for customers using 300 kWhs in a month to 18.91 percent for customers using 1,000 kWh in a month. The higher increase at the lower use levels is largely caused by the impact of the increased Service Charge. The monthly usage based upon more average residential usage levels (800 kWh per month though 1,300 kWh per month) exhibits the lowest increase. This is the result of the majority of the energy usage being charged at the lower, first block rate. Finally, the higher monthly usage amounts, starting at 2,000 kWhs per month and higher, see a higher percentage overall annual increase due to the impact of the higher rates of the second block.

This rate design continues to provide an incentive for customers to use their electric energy more efficiently. Further, the proposed rate structure sends a more accurate price signal to customers as compared to current rate structure by more closely aligning prices with costs.

Q. Are you proposing any other changes to Schedule 1?

A. No.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Darlene Nemnich
Calculation of Revenue Impact

July 29, 2011

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Residential Service
Schedule 1

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
0								
1	Service Charge	162,935	8.00	$1,303,478	10.00	$1,629,347	$325,869	25.00%
2	Mininum Charge	718	3.00	$2,155	3.00	$2,155	$0	0.00%
3	Current Energy Charge							
4	0-300 kWh	47,023,144	0.060253	$2,833,285				
5	Over 300 kWh	151,819,275	0.073884	$11,217,015				
6	Total Energy	198,842,419		$14,050,300				
7	Proposed Energy Charge							
8	Summer							
9	0-1000 kWh	30,880,485		$2,120,633	0.082222	$2,539,055	$418,422	19.73%
10	Over 1000 kWh	10,872,779		$803,324	0.100310	$1,090,648	$287,324	35.77%
11	Summer Energy	41,753,264		$2,923,958		$3,629,703	$705,745	24.14%
12	Non-Summer							
13	0-1000 kWh	97,057,335		$6,690,952	0.082222	$7,980,248	$1,289,296	19.27%
14	Over 1000 kWh	60,031,820		$4,435,391	0.091266	$5,478,864	$1,043,473	23.53%
15	Non-Summer Energy	157,089,155		$11,126,343		$13,459,112	$2,332,769	20.97%
16	Total Energy	198,842,419		$14,050,300		$17,088,815	$3,038,515	21.63%
7	Total Revenue			$15,355,933		$18,720,317	$3,364,384	21.91%
8	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
9	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
10	PSA		0.000000	$0	0.000000	$0	$0	0.00%
11	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
12	Total Billed Revenue			$15,355,933		$18,720,317	$3,364,384	21.91%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Darlene Nemnich
Typical Monthly Billing Comparison

July 29, 2011

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011

Residential Service
Schedule 1

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Summer			Non-Summer			Avg Mth Cost -12 Mths		
Line No	Energy kWh	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference
1	0	8.00	10.00	25.00%	8.00	10.00	25.00%	8.00	10.00	25.00%
2	100	14.03	18.22	29.86%	14.03	18.22	29.86%	14.03	18.22	29.86%
3	200	20.05	26.44	31.87%	20.05	26.44	31.87%	20.05	26.44	31.87%
4	300	26.08	34.67	32.94%	26.08	34.67	32.94%	26.08	34.67	32.94%
5	400	33.47	42.89	28.14%	33.47	42.89	28.14%	33.47	42.89	28.14%
6	500	40.86	51.11	25.09%	40.86	51.11	25.09%	40.86	51.11	25.09%
7	600	48.25	59.33	22.96%	48.25	59.33	22.96%	48.25	59.33	22.96%
8	700	55.63	67.56	21.45%	55.63	67.56	21.45%	55.63	67.56	21.45%
9	800	63.02	75.78	20.25%	63.02	75.78	20.25%	63.02	75.78	20.25%
10	900	70.41	84.00	19.30%	70.41	84.00	19.30%	70.41	84.00	19.30%
11	1,000	77.80	92.22	18.53%	77.80	92.22	18.53%	77.80	92.22	18.53%
12	1,050	81.49	97.24	19.33%	81.49	96.78	18.76%	81.49	96.90	18.91%
13	1,100	85.19	102.25	20.03%	85.19	101.35	18.97%	85.19	101.58	19.24%
14	1,200	92.58	112.28	21.28%	92.58	110.47	19.32%	92.58	110.92	19.81%
15	1,300	99.96	122.31	22.36%	99.96	119.60	19.65%	99.96	120.28	20.33%
16	1,400	107.35	132.34	23.28%	107.35	128.73	19.92%	107.35	129.63	20.75%
17	1,500	114.74	142.38	24.09%	114.74	137.85	20.14%	114.74	138.98	21.13%
18	2,000	151.68	192.53	26.93%	151.68	183.49	20.97%	151.68	185.75	22.46%
19	2,500	188.62	242.69	28.67%	188.62	229.12	21.47%	188.62	232.51	23.27%
20	3,000	225.57	292.84	29.82%	225.57	274.75	21.80%	225.57	279.27	23.81%
21	4,000	299.45	393.15	31.29%	299.45	366.02	22.23%	299.45	372.80	24.49%
22	5,000	373.33	493.46	32.18%	373.33	457.28	22.49%	373.33	466.33	24.91%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT D. SPARKS

July 29, 2011

Q. Please state your name and business address.

A. My name is Scott Sparks. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Senior Regulatory Analyst in the Regulatory Affairs Department. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Please describe your educational background.

A. In May of 1989, I received a Bachelor of Business Administration degree in Business Management from Boise State University. I have also completed post-graduate econometrics courses and attended the electric utility ratemaking course offered through New Mexico State University's Center for Public Utilities, as well as various advanced ratemaking courses presented by the Edison Electric Institute.

Q. Please describe your work experience.

A. I became employed by Idaho Power Company in 1985 as a part-time mail clerk and have held positions as Meter Reader, Customer Service Representative, Economic Analyst, Human Resource/Compensation Analyst, Regulatory Analyst, and Resource Planning Analyst.

In January of 1991, after two years in the Customer Service Department, I was offered and I accepted a position in the Company's Energy Services Department. My responsibilities over six years in the department varied from conservation program evaluation, special studies, load forecasting, and research. In 1995, I was asked to temporarily transfer to the Human Resources Department to assist with implementation of the Company's reorganization, benefit, and compensation plans.

In 1998, I applied for and accepted a position in the Regulatory Affairs Department where I was responsible for reviving the Company's resource planning and integrated resource planning processes. As part of reorganization, I was reassigned to the Power Supply Planning Department in 2001 where I acted as the lead analyst for the Integrated Resource Plan. In July 2003, I left the Company to pursue self-employment in the real estate and construction sectors. I returned to the Company as a Senior Regulatory Analyst in the Regulatory Affairs Department in June 2008.

Q. What is the purpose of your testimony?

A. My testimony addresses proposed changes to the Company's commercial, industrial, irrigation, lighting, and non-metered retail tariff schedules. I will also address proposed updates to the rates charged under the Company's facilities charge provisions.

Q. What are the Company's overall objectives with regard to its rate design strategy?

A. The Company's rate designs are developed to recover the revenue requirement targets provided by Mr. Matthew T. Larkin for each customer class and special contract customer. In doing so, the Company continues to maintain two important objectives with regard to rate design: (1) to establish prices that primarily reflect the costs of the services provided, and (2) to have cost-based rate proposals designed to align with and encourage energy efficiency.

I. <u>COMMERCIAL AND INDUSTRIAL</u>

Q. How is the discussion of your rate design proposals organized within your testimony for the commercial and industrial customer classes?

A. My testimony for the commercial and industrial customer classes will address rate design proposals for Schedules 7, 9, and 19, respectively.

Q. Please describe the methodology used to determine the rate component adjustments for Schedules 7, 9, and 19.

A. As part of the Company's more recent general rate cases, the Company has moved toward its objective of establishing prices that primarily reflect the costs of the services provided for the demand-metered schedules by emphasizing increases in the demand- and customer-related components and the inclusion of fewer non-energy-related costs in the energy charges. The Company's proposed methodology used to determine the rate component adjustments for Schedules 7, 9, and 19 in this case furthers that objective.

The methodology used to calculate the proposed rate component adjustments for Schedules 7, 9, and 19 represents a uniform percentage movement of 5 percent toward the unit cost-of-service intended for recovery by that rate component. In applying this methodology, the Company first considered the percentage of overall revenue that would be recovered under each billing component if each billing component was set at the full unit cost-of-service. These percentages established the target revenue for each billing component. Second, the Company determined the percentage of overall revenue currently recovered by each billing component at existing base rates. The difference, or gap, between the targeted level and the actual percentage was then determined for each billing component. The current percentage of overall revenue by billing component was then adjusted by approximately 5 percent of the gap to establish adjusted revenue targets.

A. Small General Service, Schedule 7.

Q. What is the present rate structure for Schedule 7?

A. Customers taking service under Schedule 7 pay separate monthly Service Charges for single-phase and three-phase services, a monthly seasonal Energy Charge for the first 500 kilowatt-hours ("kWh") used, and a separate seasonal Energy Charge for all usage over 500 kWh in a month. Summer Energy Charges begin on June 1 of each year and end on August 31 of each year while the non-summer Energy Charges begin on September 1 of each year and end on May 31 of each year. Schedule 7 customers do not have a Demand Charge.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 7?

A. The annual revenue requirement for Schedule 7 customers is $1,634,519. This is shown on page 4 of Mr. Larkin's Exhibit 1007.

Q. Please describe the proposed rate design adjustments for Schedule 7.

A. For all energy components, the Company is proposing rates that represent a uniform 5 percent movement towards the costs to serve that rate component. All rate design adjustments for Schedule 7 are included on page 1 of Exhibit 1201 and target the proposed class revenue increase of 4.82 percent shown on page 4 of Mr. Larkin's Exhibit 1007.

Q. Have you prepared an exhibit that illustrates the impact of the proposed rate adjustments on Small General Service customers?

A. Yes. Page 1 of Exhibit 1202 shows the billing comparison between Schedule 7 existing rates and proposed rates for typical billing levels.

B. Large General Service, Schedule 9.

Q. In general terms, what is the current rate structure for Schedule 9?

A. Service under Schedule 9 may be taken at a Secondary, Primary, or Transmission Service level. All customers taking service under Schedule 9 pay a Service Charge, a Basic Charge, and both summer and non-summer Energy and Demand Charges. Customers taking Primary or Transmission service may also pay a facilities charge for Company-owned facilities installed beyond Idaho Power's Point of Delivery.

1. Large General Service, Schedule 9 – Secondary.

Q. What is the current rate structure for Schedule 9 Secondary Service?

A. The current rate structure for Schedule 9 Secondary Service includes separate monthly Service Charges for single-phase and three-phase services, a Basic Charge, and seasonal Demand and Energy Charges.

Q. What is the revenue requirement for customers taking Secondary Service under Schedule 9?

A. The annual revenue requirement for customers taking Secondary Service under Schedule 9, as shown on page 4 of Mr. Larkin's Exhibit 1007, is $7,756,452.

Q. Have you prepared an exhibit that illustrates the rate design proposal for revenue recovery under Schedule 9 Secondary Service?

A. Yes, the rate design proposal for Schedule 9 Secondary Service is included on page 2 of Exhibit 1201 and targets the proposed class revenue increase of 11.19 percent shown on page 4 of Mr. Larkin's Exhibit 1007. As previously described, for all rate components, the Company is proposing rates that represent a uniform 5 percent movement towards the costs to serve that rate component. The costs to serve each rate component are detailed on page 3 of Mr. Larkin's Exhibit 1006.

Q. Have you prepared an exhibit that shows the impact of the rate design on Schedule 9 Secondary Service level customers?

A. Yes. Pages 2-4 of Exhibit 1202 show the billing comparison between the Schedule 9 Secondary Service level existing rates and proposed rates for typical billing levels. As can be seen from this exhibit, for each Demand level, higher load factor customers will see a lower overall increase as compared to low load factor customers.

2. Large General Service, Schedule 9 - Primary and Transmission.

Q. What is the current rate structure for Schedule 9 Primary and Transmission Service?

A. All customers taking service under Schedule 9 Primary or Transmission Service pay a Service Charge, a Basic Charge, a summer On-Peak Demand Charge, and seasonal time-of-use Demand and Energy Charges. Customers may also pay a facilities charge for Company-owned facilities installed beyond Idaho Power's Point of Delivery.

Q. What is the revenue requirement to be recovered from Schedule 9 customers taking Primary Service?

A. The annual revenue requirement for Schedule 9 Primary Service customers, as shown on page 4 of Mr. Larkin's Exhibit 1007, is $840,530.

Q. Have you prepared an exhibit that illustrates the rate design proposal for revenue recovery of Primary Service under Schedule 9?

A. Yes, the rate design proposal for Schedule 9 Primary Service is included on pages 3 of Exhibit 1201 and targets the proposed class revenue increase of 5.32 percent shown on page 4 of Mr. Larkin's Exhibit 1007. For all rate components, the Company is proposing rates that represent a uniform 5 percent movement towards the costs to serve that rate component. The costs to serve each rate component are detailed on page 3 of Mr. Larkin's Exhibit 1006.

Q. Have you prepared an exhibit that shows the billing impact of this rate design proposal on customers receiving Primary Service under Schedule 9?

A. Yes. Pages 5-7 of Exhibit 1202 show the billing comparisons between the existing rates and proposed rates for Schedule 9 Primary Service.

Q. What is the revenue requirement to be recovered from Schedule 9 customers taking Transmission Service?

A. As shown on page 4 of Mr. Larkin's Exhibit 1007, the annual revenue requirement for Schedule 9 Transmission Service customers is $154,997; however, no class revenue increase is required to recover this revenue requirement as determined by the Company's cost-of-service study.

Q. Are you proposing any other changes to Schedule 9?

A. Yes. The Company is proposing to change the section heading of "Power Factor" to "Power Factor Adjustment". This clarification is a more accurate description of the section and it aligns with the "Power Factor Adjustment" headings listed under Schedules 19 and 24.

C. Large Power Service, Schedule 19.

Q. What is the current rate structure for Schedule 19?

A. Service under Schedule 19, just like service under Schedule 9, is provided at Secondary, Primary, and Transmission Service levels. All customers taking service under Schedule 19 pay a Service Charge, a Basic Charge, a summer On-Peak Demand Charge, and seasonal time-of-use Demand and Energy Charges. Customers taking Primary or Transmission Service may also pay a facilities charge for Company-owned facilities installed beyond Idaho Power's Point of Delivery. In addition, Schedule 19 includes a 1,000 kW per month minimum Billing Demand and Basic Load Capacity Charge.

Q. What is the revenue requirement to be recovered from Large Power Service customers taking service under Schedule 19 Secondary Service?

A. No customers in the Company's Oregon jurisdiction are currently served under Schedule 19 Secondary Service; therefore, there is no revenue requirement for Secondary Service. Nevertheless, the Company is proposing to increase each rate component by the same 11.19 percent of overall revenue increase determined for Schedule 9 Secondary Service. This will ensure that the current cost-of-service relationships continue to exist for Secondary Service in Schedules 9 and 19.

Q. What is the revenue requirement to be recovered from Large Power Service customers taking Primary Service under Schedule 19?

A. The annual revenue requirement for Schedule 19 Primary Service customers, as shown on page 4 of Mr. Larkin's Exhibit 1007, is $8,213,065.

Q. Please describe the rate design proposal for Schedule 19 Primary Service.

A. As determined by the Company's cost-of-service study, the rate design for Schedule 19 Primary Service does not require a class revenue increase to recover the annual revenue requirement.

Q. What is the revenue requirement to be recovered from Large Power Service customers taking service under Schedule 19 Transmission Service?

A. The annual revenue requirement for Schedule 19 Transmission Service customers, as shown on page 4 of Mr. Larkin's Exhibit 1007, is $3,690,168.

Q. Have you prepared an exhibit that illustrates the proposed rate design to recover the annual revenue requirement for Schedule 19 Transmission Service?

A. Yes, the rate design proposal for Schedule 19 Transmission Service is shown on page 6 of Exhibit 1201 and targets the proposed class revenue increase of 18.15 percent shown on page 5 of Mr. Larkin's Exhibit 1007. For all rate components, the Company is proposing rates that represent a uniform 5 percent movement towards the costs to serve that rate component. The costs to serve each rate component are indicated on page 4 of Mr. Larkin's Exhibit 1006.

Q. Have you prepared an exhibit that shows the billing comparisons between the existing rates and the proposed rates for Schedule 19 Transmission Service customers?

A. Yes. Pages 8-10 of Exhibit 1202 show the billing comparisons between the existing rates and the proposed rates for Schedule 19 Transmission Service customers. As with Schedule 9 Primary Service, for each Demand level, the higher load factor customers will see a lower overall increase as compared to low load factor customers.

II. IRRIGATION

A. Schedule 24 – Agricultural Irrigation Service.

Q. What is the current rate structure for Schedule 24?

A. Service under Schedule 24 is classified as being either "in-season" or "out-of-season." The in-season for each customer begins with the customer's meter reading for the May billing period and ends with the customer's meter reading for the September billing period. The out-of-season encompasses all other billing periods.

For the in-season, customers pay a higher monthly Service Charge than during the out-of-season to encourage customers to continue service throughout the out-of-season period.

Customers pay both an Energy Charge and a Demand Charge for metered usage during the in-season. The Energy Charge utilizes a load-factor pricing mechanism by separating charges into two energy blocks. The first block charges irrigation customers a monthly rate per kWh for the first 164 kWh per kW of demand. The second block charges customers a lower monthly energy rate per kWh for all other energy use to encourage installation of energy efficient irrigation systems with reduced demand and longer hours of operation. Customers pay an in-season Demand Charge only. During the out-of-season, customers pay a flat Energy Charge per kWh for all energy use.

Both Secondary Service and Transmission Service are available under Schedule 24, although no customers are currently taking Transmission Service.

Q. What is the revenue requirement to be recovered from Schedule 24?

A. The total annual revenue to be recovered from customers taking service under Schedule 24, as shown on page 5 of Mr. Larkin's Exhibit 1007, is $4,467,754.

Q. Please describe the rate design proposal for Schedule 24.

A. Consistent with the overall rate design objectives, the Company is proposing to move the individual rate components 5 percent closer to the costs indicated by Mr. Larkin's class cost-of-service study as shown on page 4 of Exhibit 1006. The rate design proposal on page 9 of Exhibit 1201 targets the capped 29.34 percent average revenue increase indicated on page 4 of Mr. Larkin's Exhibit 1007.

In addition to moving each rate component closer to the cost-of-service, the Company is also proposing to increase the pricing differential between energy blocks for the in-season load factor pricing mechanism. Out-of-season energy sales will not be impacted by the proposed change to the load-factor energy rates.

Q. Why are you proposing to increase the differential between the current load factor energy pricing blocks?

A. By increasing the differential between the in-season load factor energy pricing blocks, a stronger pricing signal will be sent to irrigators encouraging them to install and operate their irrigation systems in a manner that utilizes the electric system more efficiently.

Q. What is the current price differential between the first and second load factor energy blocks?

A. The current price differential between the first and second load factor energy blocks is 3 percent.

Q. What price differential is the Company proposing between the first and second energy blocks?

A. The Company is proposing to increase the load factor pricing differential from 3 percent to 6 percent. As stated in my testimony in Docket No. UE 213, the 3 percent differential was established as an introductory rate design to help familiarize customers with the load factor pricing structure.

Q. How were the rates for Schedule 24 Transmission Service determined?

A. Once the percentage revenue change for each rate component was determined for Secondary Service, the same percentage changes were applied to each component for Transmission Service. No irrigation customers are currently served under Transmission Service.

Q. Have you prepared an exhibit that shows the billing impact of the rate design on Schedule 24 irrigation service customers?

A. Yes. Pages 11-13 of Exhibit 1202 show the impact on customers' bills of the proposed rate adjustments for Schedule 24 Secondary Service. As can be seen from Exhibit 1202, with load factor pricing, customers with the highest percentage increase in annual bills have the lowest average load factors. Similarly, the higher a customer's load factor, the more beneficial the rate structure tends to be in terms of the overall impact to the annual billing.

III. LIGHTING

Q. How have you organized the discussion of the rate design proposals for area lighting, unmetered service, street lighting and traffic control signal lighting?

A. The discussion of rate design proposals for lighting will address Schedules 15 (Dusk to Dawn Customer Lighting), 40 (Unmetered General Service), 41 (Street Lighting Service), and 42 (Traffic Control Signal Lighting Service), respectively.

A. Dusk To Dawn Customer Lighting, Schedule 15.

Q. What is the current rate structure for Dusk to Dawn Customer Lighting under Schedule 15?

A. Customers taking service under Schedule 15 are charged on a per lamp basis. Lamps currently served under Schedule 15 include 100, 200, and 400 watt high pressure sodium vapor area lighting, 200 and 400 watt high pressure sodium vapor flood lighting, and 400 and 1,000 watt metal halide flood lighting.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 15?

A. The annual revenue requirement for Schedule 15 customers, as shown on page 4 of Mr. Larkin's Exhibit 1007, is $112,462.

Q. Please describe the rate design proposal for Schedule 15.

A. The rate design proposal for Schedule 15 is included on page 5 of Exhibit 1201 and does not include any rate adjustments to recover the proposed revenue requirement. Although no rate adjustments are required, the Company is proposing to update the monthly lamp charges based upon the actual cost-of-service for each lamp size offered under Schedule 15. My workpapers detail the updated actual cost-of-service for each lamp size.

Q. Is the Company proposing any other changes to Schedule 15?

A. Yes, the Company is proposing to update the facilities charge from 1.75 percent to 1.51 percent to more accurately reflect current costs. The derivation of the updated facilities charge is addressed later in my testimony.

B. Unmetered General Service, Schedule 40.

Q. What is the present rate structure for Unmetered General Service under Schedule 40?

A. Customers taking service under Schedule 40 are non-metered but have energy loads and periods of operation which are fixed. A customer's estimated usage is charged a flat Energy Charge. Demand- and customer-related costs are also recovered through the Energy Charge. The minimum bill for service under Schedule 40 is $1.50 per month. With Company approval, an Intermittent Usage Charge, per unit, per month, may be charged to municipalities or agencies of federal, state, or county governments having the potential of intermittent variations in energy usage.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 40?

A. The annual revenue requirement for Schedule 40 customers, as shown on page 4 of Mr. Larkin's Exhibit 1007, is $1,133.

Q. Please describe the rate design proposal for Schedule 40.

A. The rate design proposal for Schedule 40 is included on page 11 of Exhibit 1201. It targets the proposed class revenue increase of 16.60 percent as shown on page 4 of Mr. Larkin's Exhibit 1007.

Q. Are any other changes being proposed to Schedule 40?

A. Yes. The Company is proposing to remove language in the Applicability section of Schedule 40 indicating that service under this schedule may include "street and highway lighting". The Company is proposing that all street lighting systems be served under Schedule 41, Street Lighting Service, to more accurately reflect the Company's cost to serve these types of facilities. The Company is also proposing to rename Schedule 40 from "Unmetered" General Service to "Non-Metered" General Service in an effort to maintain consistent use of terms throughout all schedules.

C. Street Lighting Service, Schedule 41.

Q. What is the present rate structure for Street Lighting Service under Schedule 41?

A. The current rate structure for Schedule 41 provides two service options for street lighting customers. Option "A" provides for Idaho Power-owned and Idaho Power-maintained street lighting systems. Street lighting systems under this option are not metered and customers pay monthly lamp charges based on their choice of standard wattage high pressure sodium vapor lamps. Standard wattages include 70, 100, 200, 250, and 400 watts. The monthly lamp charges under Option "A" reflect the

Company's cost to provide energy, install the street lighting system, and provide ongoing maintenance.

Option "B" provides for customers choosing to own and install their own street lighting systems. Under this option, street lighting systems may be metered or non-metered. For metered systems, maintenance may be provided by the customer or by Idaho Power. For non-metered systems, Idaho Power provides maintenance.

As in Option "A", standard wattages include 70, 100, 200, 250, and 400 watts. The monthly lamp charges for non-metered service reflect the Company's cost to provide energy, install lamps, and provide ongoing maintenance of the lamps only. For metered systems, customers may choose to provide their own maintenance and incur a kWh charge for their energy usage only or request maintenance from Idaho Power. In the latter case, customers pay an additional monthly maintenance charge based on their choice of installed standard wattage high pressure sodium vapor lamps (70, 100, 200, 250, and 400 watts).

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 41?

A. The annual revenue requirement for Schedule 41 is $128,425 as shown on page 4 of Mr. Larkin's Exhibit 1007. Based on results from the Company's cost-of-service study, the Company is not proposing a rate adjustment to recover this revenue requirement.

Q. Please describe the rate design proposal for Schedule 41.

A. The rate design proposal for Schedule 41 is included on pages 12-15 of Exhibit 1201. These pages outline the proposed new service options and monthly charges for street lighting service under Schedule 41.

Q. Please explain why the Company is proposing to modify Schedule 41 provisions and offer new service options.

A. The Company is proposing to modify Schedule 41 in an effort to meet customer needs resulting from the introduction of new and enhanced street lighting technologies. In recent years, the Company has received a growing number of inquiries from street lighting customers, namely cities and municipalities, concerning the inability of the existing street lighting rate schedule to properly address energy charges and maintenance provisions related to new lighting technologies.

Q. What specific changes is Idaho Power proposing for Schedule 41?

A. Based on the Company's internal evaluation and interaction with current street lighting customers, the Company is proposing changes for street lighting service that will: 1) update all existing charges to reflect the current cost-of-service, 2) add language requiring that all new customer-owned street lighting systems installed outside of subdivisions be metered and maintained by the customer, 3) modify the existing Option "B" to apply to customer-owned and Idaho Power-maintained street lighting systems only, and 4) add a new Option "C" for customer-owned and customer-maintained street lighting systems.

Q. Please describe the charges that are being updated in Schedule 41.

A. The Company is proposing to update the accelerated replacement charge, lamp charges, meter charges, energy charges, and facilities charges in an effort to more accurately represent actual costs.

Q. How did the Company update these charges to reflect the actual cost-of-service?

A. The Company conducted a new cost-of-service analysis for the accelerated replacement charge, lamp charges, meter charges, and energy charges under Schedule 41. The update to the facilities charge under Schedule 41 is described later in my testimony.

Q. Please describe the methodology used in cost-of-service analysis to update charges.

A. The cost-of-service methodology used to update the accelerated replacement charge, lamp charges, meter charges, and energy charges determined the actual cost to provide these services. The analysis examined the Company's labor costs, lamp and fixture costs, maintenance costs, sales taxes, overheads, vehicle costs, metering costs, and energy costs to determine the updated charges. A complete breakout of these costs and the methodology used to update charges is contained in my workpapers.

Q. Please describe the proposed service options under the proposed Schedule 41.

A. The Company is proposing to offer three service options under Schedule 41:

- "A" – Idaho Power-Owned, Idaho Power-Maintained System
- "B"- Customer-Owned, Idaho Power-Maintained System
- "C" – Customer-Owned, Customer-Maintained System

Options "A" and "B" are currently offered under Schedule 41 while Option "C" is a newly proposed section.

Q. Please describe Option "A".

A. Option "A" provides for non-metered, high pressure sodium vapor lighting systems that are installed, owned, operated, and maintained by Idaho Power. Customers choosing this option are required to pay a monthly per lamp charge to cover the cost of energy, materials, and maintenance provided by the Company.

Q. Please describe the proposed updates to Option "A".

A. In an effort to clarify the requirements for receiving service under Option "A", the Company is proposing to change the heading from "Overhead Lighting – Company-Owned System" to "Idaho Power-Owned, Idaho Power-Maintained System". As mentioned above, all existing lamp, pole, and facilities charges have been updated to more accurately reflect the current cost of providing street lighting service.

Q. Is the Company proposing to offer any new lighting technologies, such as light emitting diodes (LEDs), under Option "A"?

A. No. Idaho Power is not proposing to offer new lighting technologies on Idaho Power-owned street lighting systems due to high product costs and unproven energy and maintenance savings. Although LEDs are an attractive option for customers receiving federal grants or other forms of additional funding, the Company has determined that the monthly charges needed to offer these products on its own lighting systems would be too high to attract customer participation. This was confirmed in an informal assessment of existing street lighting customers. Nevertheless, the Company will continue to evaluate the cost, energy savings, and maintenance savings of LEDs and other new lighting technologies on an ongoing basis.

Q. What changes are being proposed for Option "B" in Schedule 41?

A. Option "B" has been modified to include customer-owned and Idaho Power-maintained street lighting systems only. This service option will only be offered to existing customers that desire to have Idaho Power maintain their high pressure sodium vapor street light systems. As proposed, no new service will be allowed under this option as the Company implements its new policy requiring that all new customer-owned systems are metered and maintained by the customer. In Oregon, since all existing lighting systems under Option "B" are non-metered and no new service is proposed for this option, the Company is proposing to remove all monthly charges for Metered Service under this option.

Q. Why are you proposing to add Option "C" to Schedule 41?

A. The proposed provisions and charges under Option “C” are designed for customers that own their own lighting systems and desire to install new and unique lighting technologies and designs that are not offered by the Company. This option will also allow customers with non-metered systems to provide their own maintenance without being charged for Idaho Power-provided maintenance, as is the case under the current rate design.

Ultimately, over time, the Company anticipates that Option “C” will become the primary service option for customer-owned street lighting systems as it transitions to requiring meters and customer-provided maintenance on all new customer-owned lighting systems. This new provision will provide customers greater flexibility as they seek to install new and unique lighting technologies that are not standard to Idaho Power.

Q. Is the Company proposing to require metering on street lighting systems installed inside subdivisions?

A. No. The Company is not proposing to require metering on street lighting systems installed inside subdivisions for two reasons: 1) this requirement would create additional maintenance costs for customers and 2) this requirement would require installation of duplicate infrastructure.

Typically, developers of subdivisions are required to install street lighting systems inside subdivisions at the request of municipalities or agencies of federal, state, or county governments. Once installed, the municipality assumes ownership of the street lighting system and provides ongoing maintenance. As pointed out in conversations with various cities, a requirement to install meters for street lighting inside of subdivisions would necessitate installation of duplicate infrastructure and would not be supported by some municipalities. In many cases, developers would need to install meter cabinets, a second conduit/circuit system for the lighting, and in some cases a third conduit/circuit for the irrigation system power. In the long-term, cities would have to maintain the second circuit system including dig-line markings, additional junction boxes and connections, as well as multiple meter cabinets.

D. Traffic Control Signal Lighting Service, Schedule 42.

Q. What is the present rate structure for Schedule 42?

A. Customers taking service under Schedule 42 pay an Energy Charge for each kWh of estimated energy use for non-metered systems and for each kWh of actual usage for metered systems. For non-metered systems, usage is estimated based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated. There is no minimum charge under Schedule 42.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 42?

A. The annual revenue requirement for Schedule 42 customers, as shown on page 4 of Mr. Larkin's Exhibit 1007, is $1,592.

Q. Please describe the rate design proposal for Schedule 42.

A. The rate design proposal for Schedule 42 is included on page 16 of Exhibit 1201. It targets the proposed capped class revenue increase of 29.34 percent shown on page 4 of Mr. Larkin's Exhibit 1007.

IV. FACILITIES CHARGES

Q. What change is the Company proposing to facilities charges?

A. The Company is proposing to update the rates that customers pay under Idaho Power's facilities charge provisions to more accurately reflect the Company's current costs to own, operate, and maintain facilities installed beyond Idaho Power's Point of Delivery.

Q. How are the current facilities charge rates established?

A. The effective facilities charge rates in the Company's Oregon jurisdiction are set equal to the facilities charge rates in its Idaho jurisdiction. Because the Company recently filed to update its facilities charge rates in Idaho (Case No. IPC-E-11-08), it is proposing to update its facilities charge rates in Oregon to maintain existing cost-of-service relationships.

Q. Please explain Idaho Power's existing facilities charge provisions.

A. At the option of the Company, facilities charges may be offered to Primary and Transmission Service level customers under Schedule 9 (Large General Service) and Schedule 19 (Large Power Service). Facilities charges may be offered to Transmission Service level customers only under Schedule 24 (Agricultural Irrigation Service). If offered, and in consideration of a Customer paying a monthly facilities charge, the Company will own, operate, and maintain facilities installed beyond Idaho Power's Point of Delivery.

As of August 8, 2005, customers taking service under Schedule 15 (Dusk to Dawn Customer Lighting) and Schedule 41 (Street Lighting Service) were no longer eligible for facilities charges although some customers continue to pay monthly facilities charges for facilities installed prior to August 8, 2005.

Q. What rates do eligible customers pay under the current facilities charge provisions?

A. Customers taking Primary or Transmission Service under Schedules 9 and 19, and Transmission Service under Schedule 24, pay a facilities charge rate of 1.7 percent per month of the Company's total investment in facilities installed beyond Idaho Power's Point of Delivery.

Customers taking service under Schedules 15 and 41 pay a facilities charge rate of 1.75 percent per month of the Company's investment in facilities installed prior to August 8, 2005. Eligible facilities installed under Schedules 15 and 41 included overhead secondary, poles, anchors, and underground circuits. Costs for these facilities are charged through work orders.

Q. What monthly rates is the Company proposing for facilities charges?

A. The Company is proposing to update the monthly facilities charge rate to 1.41 percent for customers taking Primary or Transmission Service under Schedules 9 and 19. The Company is also proposing a rate of 1.41 percent for customers taking Transmission Service under Schedule 24.

For customers taking service under Schedule 15, the Company is proposing a rate of 1.51 percent per month and for Schedule 41, the Company is proposing a rate of 1.21 percent per month.

Q. What cost components were used to update the current facilities charge rates?

A. The cost components used to update the facilities charge rates include:

- Rate of Return
- Depreciation
- Income Taxes
- Property Taxes
- Other Taxes (Regulatory Fees)
- Operation and Maintenance Expenses
- Administration and General Expenses
- Working Capital
- Insurance

Q. Please describe the individual cost components that are used to derive the Company's facilities charges.

A. The cost components used to derive the Company's facilities charges are the same components included in the Company's revenue requirement for like facilities. Descriptions of each cost component are as follows:

Rate of Return – Idaho Power's cost of financing its original investment in facilities. This uses a weighted average of the Company's cost of debt and cost of equity. The facilities charge methodology uses a level payment stream to simplify the rate calculation and the administration of the facilities charge. The Rate of Return used to determine the facilities charge will be the Rate of Return ordered by the Commission in this filing.

Booked Depreciation – The straight-line annual depreciation of assets based on a levelized 31-year basis.

Income Taxes – The tax that Idaho Power pays on the amount of revenue received from the equity portion of the Rate of Return.

Property Taxes – The tax that Idaho Power pays for its distribution facilities. Each dollar the Company invests beyond the Point of Delivery is assessed property taxes.

Other Taxes (Regulatory Fees) – The taxes and fees that Idaho Power pays to the Idaho and Oregon public utilities commissions. A portion of these fees is tied to the Company's distribution investment which includes facilities installed beyond the Company's Point of Delivery.

Operation and Maintenance Expenses – Includes all of Idaho Power's costs to operate and maintain its distribution facilities. This cost component represents an average maintenance rate for all distribution equipment.

Administration and General Expenses – Represents an expense based on total Administration and General as a percentage of total plant investment.

Working Capital – Working Capital is the carrying cost of inventory. Working Capital is based on the cost of capital to finance the distribution facilities inventory and the property taxes that the Company pays on its inventory.

Insurance – The insurance rate reflects the additional cost Idaho Power incurs for insurance premiums resulting from facilities installed beyond the Company's Point of Delivery. This insurance rate covers property, casualty, and worker's compensation. It does not cover facility replacement costs for failed facilities.

Q. What are the proposed percentage amounts for each cost component by rate class?

A. The proposed percentage amounts used to derive the proposed facilities charge rates are as follows:

	Cost Components	**Rate 15**	**Rate 19**	**Rate 41**
1	Rate of Return	4.81%	4.81%	4.81%
2	Book Depreciation	3.23%	3.23%	3.23%
3	Income Taxes	1.90%	1.90%	1.90%
4	Property Taxes	0.56%	0.56%	0.56%
5	Other Taxes (Regulatory Fees)	0.14%	0.14%	0.14%
6	Operation & Maintenance	4.73%	3.58%	1.18%
7	Administration & General	2.28%	2.28%	2.28%
8	Working Capital	0.14%	0.14%	0.14%
9	Insurance	0.32%	0.32%	0.32%
10	Annual Total	18.10%	17.00%	14.60%
11	Monthly Rate	1.51%	1.41%	1.21%

Q. Please explain why Schedules 9 and 24 are not identified in the table.

A. Under Idaho Power's approved rate schedules, the facilities charge rates for Schedules 9 and 24 are aligned with the derived rate for Schedule 19.

Q. What cost component has driven the proposed reduction in the facilities charge rates?

A. The primary cost component that has driven the reduction in the facilities charge rates is the Rate of Return, which has decreased since the last update.

Q. What is the estimated reduction in the Company's revenue from the proposed facilities charge rates?

A. The estimated reduction in revenue received through facilities charges in the Oregon jurisdiction under the Company's proposal is approximately $76,200 per year.

Q**. How will the reduction in revenue for facilities charges affect the energy rates of customer classes?**

A. The reduction in revenue will result in higher revenue requirements for each customer class that collects facilities charge revenue, namely Schedules 9, 15, 19, 24, and 41. In turn, the energy rates for these customer classes will increase slightly to recover the decline in facilities charge revenue.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Calculation of Revenue Impact

July 29, 2011

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Small General Service
Schedule 7

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Serivce Charge:							
2	Single-Phase	24,881	8.60	$213,977	10.00	$248,811	$34,834	16.28%
3	Three Phase	4,824	17.20	$82,975	18.00	$86,834	$3,859	4.65%
4	Total Billings	29,705		$296,952		$335,645	$38,693	13.03%
5	Minimum Charge	35	3.00	$106	3.00	$106	$0	0.00%
6	Energy Charge							
7	Summer							
8	0-500 kWh	2,093,316	0.064775	$135,595	0.066540	$139,289	$3,694	2.72%
9	Over 500 kWh	2,304,996	0.085776	$197,713	0.091026	$209,815	$12,102	6.12%
10	Summer Energy	4,398,313		$333,308		$349,104	$15,796	4.74%
11	Non-Summer							
12	0-500 kWh	6,214,174	0.064775	$402,523	0.066540	$413,491	$10,968	2.72%
13	Over 500 kWh	7,230,410	0.072819	$526,511	0.074155	$536,171	$9,660	1.83%
14	Non-Summer Energy	13,444,583		$929,034		$949,662	$20,628	2.22%
15	Total Energy	17,842,896		$1,262,342		$1,298,766	$36,424	2.89%
16	Total Revenue			$1,559,400		$1,634,517	$75,117	4.82%
17	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
18	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
19	PSA		0.000000	$0	0.000000	$0	$0	0.00%
20	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
21	Total Billed Revenue			$1,559,400		$1,634,517	$75,117	4.82%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Large General Service - Secondary
Schedule 9

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge:							
2	Single-Phase	4,309	9.50	$40,940	11.00	$47,404	$6,464	15.79%
3	Three Phase	6,390	16.75	$107,036	19.00	$121,414	$14,378	13.43%
4	Total Billings	10,700		$147,976		$168,818	$20,842	14.08%
5	Minimum Charge	8	5.00	$41	5.00	$41	$0	0.00%
6	Basic Charge (per kW)	505,535	0.50	$252,768	0.75	$379,151	$126,383	50.00%
7	Demand Charge							
8	Summer	82,732	4.90	$405,388	6.03	$498,876	$93,488	23.06%
9	Non-Summer	280,625	4.12	$1,156,174	4.53	$1,271,230	$115,056	9.95%
10	Total Demand	363,357		$1,561,562		$1,770,106	$208,544	13.35%
11	Energy Charge							
12	Summer	25,642,384	0.046904	$1,202,730	0.050845	$1,303,787	$101,057	8.40%
13	Non-Summer	88,613,835	0.043005	$3,810,838	0.046658	$4,134,544	$323,706	8.49%
14	Total Energy	114,256,219		$5,013,568		$5,438,331	$424,763	8.47%
15	Total Revenue			$6,975,915		$7,756,447	$780,532	11.19%
16	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
17	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
18	PSA		0.000000	$0	0.000000	$0	$0	0.00%
19	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
20	Total Billed Revenue			$6,975,915		$7,756,447	$780,532	11.19%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Large General Service - Primary
Schedule 9

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge	60	200.00	$12,000	207.00	$12,420	$420	3.50%
2	Minimum Charge	0	10.00	$0	10.00	$0	$0	0.00%
3	Basic Charge (per kW)	44,344	0.97	$43,014	1.17	$51,882	$8,868	20.62%
4	Demand Charge							
5	Summer	8,596	4.70	$40,399	5.61	$48,221	$7,822	19.36%
6	Non-Summer	26,370	4.35	$114,711	4.58	$120,776	$6,065	5.29%
7	Total Demand	34,966		$155,110		$168,997	$13,887	8.95%
8	On-Peak Summer	8,411	0.69	$5,803	0.82	$6,897	$1,094	18.85%
9	Energy Charge							
10	Summer On-peak	1,006,729	0.044884	$45,186	0.046211	$46,522	$1,336	2.96%
11	Summer Mid-peak	1,545,559	0.041992	$64,901	0.043226	$66,808	$1,907	2.94%
12	Summer Off-peak	1,097,115	0.040101	$43,995	0.041279	$45,288	$1,293	2.94%
13	Total Summer	3,649,404		$154,082		$158,618	$4,536	2.94%
14	Non-Summer Mid-peak	7,022,860	0.037856	$265,857	0.039061	$274,320	$8,463	3.18%
15	Non-Summer Off-peak	4,426,824	0.036648	$162,234	0.037814	$167,396	$5,162	3.18%
16	Total Non-Summer	11,449,684		$428,091		$441,716	$13,625	3.18%
17	Total Energy	15,099,088		$582,173		$600,334	$18,161	3.12%
18	Total Revenue			$798,100		$840,530	$42,430	5.32%
19	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
20	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
21	PSA		0.000000	$0	0.000000	$0	$0	0.00%
22	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
23	Total Billed Revenue			$798,100		$840,530	$42,430	5.32%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Large General Service - Transmission
Schedule 9

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge	12	200.00	$2,400	200.00	$2,400	$0	0.00%
2	Minimum Charge	0	10.00	$0	10.00	$0	$0	0.00%
3	Basic Charge (per kW)	13,732	0.30	$4,119	0.30	$4,119	$0	0.00%
4	Demand Charge							
5	Summer	3,114	3.59	$11,180	3.59	$11,180	$0	0.00%
6	Non-Summer	8,667	3.84	$33,282	3.84	$33,282	$0	0.00%
7	Total Demand	11,782		$44,462		$44,462	$0	0.00%
8	On-Peak Summer	2,100	0.69	$1,449	0.69	$1,449	$0	0.00%
9	Energy Charge							
10	Summer On-peak	176,357	0.042176	$7,438	0.042176	$7,438	$0	0.00%
11	Summer Mid-peak	293,331	0.039483	$11,582	0.039483	$11,582	$0	0.00%
12	Summer Off-peak	170,420	0.037722	$6,429	0.037722	$6,429	$0	0.00%
13	Total Summer	640,108		$25,449		$25,449	$0	0.00%
14	Non-Summer Mid-peak	1,302,103	0.035631	$46,395	0.035631	$46,395	$0	0.00%
15	Non-Summer Off-peak	890,298	0.034507	$30,721	0.034507	$30,721	$0	0.00%
16	Total Non-Summer	2,192,401		$77,116		$77,116	$0	0.00%
17	Total Energy	2,832,509		$102,565		$102,565	$0	0.00%
18	Total Revenue			$154,995		$154,995	$0	0.00%
19	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
20	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
21	PSA		0.000000	$0	0.000000	$0	$0	0.00%
22	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
23	Total Billed Revenue			$154,995		$154,995	$0	0.00%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Dusk-to-Dawn Customer Lighting
Schedule 15

Line No	Description	(1) Use	(2) Lamps	(3) Current Base Rate	(4) Current Base Revenue	(5) Proposed Base Rate	(6) Proposed Base Revenue	(7) Revenue Difference	(8) Percent Change
1	Area Lighting:								
2	High Pressure Sodium Vapor:								
3	100 Watt	346,288	8,879	9.62	85,416	10.37	92,075	$6,659	7.80%
4	200 Watt	57,522	778	15.38	11,966	12.40	9,647	($2,319)	(19.38)%
5	400 Watt	28,366	181	24.37	4,411	16.96	3,070	($1,341)	(30.40)%
6	Flood Lighting:								
7	High Pressure Sodium Vapor:								
8	200 Watt	19,611	265	18.66	4,945	15.00	3,975	($970)	(19.62)%
9	400 Watt	32,149	205	27.67	5,672	17.77	3,643	($2,029)	(35.77)%
10	Metal Halide:								
11	400 Watt	0	0	30.93	0	16.26	0	$0	0.00%
12	1000 Watt	0	0	56.22	0	26.07	0	$0	0.00%
13	Total	483,936	10,308		112,410		112,410	$0	0.00%
14	Minimum Charge		17.6	3.00	53	3.00	53	$0	0.00%
15	Total Revenue				$112,463		$112,463	$0	0.00%
16	Solar PV Pilot Program Rider			0.00%	$0	0.00%	$0	$0	0.00%
17	Energy Efficiency Rider			0.00%	$0	0.00%	$0	$0	0.00%
18	PSA			0.000000	$0	0.000000	$0	$0	0.00%
19	APCU - March Forecast			0.000000	0	0.000000	0	$0	0.00%
20	Total Billed Revenue				$112,463		$112,463	$0	0.00%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Large Power Service - Secondary
Schedule 19

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge	0	200.00	$0	222.00	$0	$0	0.00%
2	Minimum Charge	0	10.00	$0	10.00	$0	$0	0.00%
3	Basic Charge (per kW)	0	0.50	$0	0.56	$0	$0	0.00%
4	Demand Charge							
5	Summer	0	4.21	$0	4.68	$0	$0	0.00%
6	Non-Summer	0	4.12	$0	4.58	$0	$0	0.00%
7	Total Demand	0		$0		$0	$0	0.00%
8	On-Peak Summer	0	0.69	$0	0.77	$0	$0	0.00%
9	Energy Charge							
10	Summer							
11	On-Peak	0	0.050984	$0	0.056689	$0	$0	0.00%
12	Mid-Peak	0	0.040142	$0	0.044634	$0	$0	0.00%
13	Off-Peak	0	0.035457	$0	0.039425	$0	$0	0.00%
14	Non-Summer							
15	Mid-Peak	0	0.037893	$0	0.042133	$0	$0	0.00%
16	Off-Peak	0	0.034278	$0	0.038114	$0	$0	0.00%
17	Total Energy	0		$0		$0	$0	0.00%
18	Total Revenue			$0		$0	$0	0.00%
19	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
20	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
21	PSA		0.000000	$0	0.000000	$0	$0	0.00%
22	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
23	Total Billed Revenue			$0		$0	$0	0.00%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Large Power Service - Primary
Schedule 19

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge	72	200.00	$14,400	200.00	$14,400	$0	0.00%
2	Minimum Charge	0	10.00	$0	10.00	$0	$0	0.00%
3	Basic Charge (per kW)	358,346	0.97	$347,596	0.97	$347,596	$0	0.00%
4	Demand Charge							
5	Summer	82,590	4.70	$388,174	4.70	$388,174	$0	0.00%
6	Non-Summer	246,450	4.35	$1,072,055	4.35	$1,072,055	$0	0.00%
7	Total Demand	329,040		$1,460,229		$1,460,229	$0	0.00%
8	On-Peak Summer	79,648	0.69	$54,957	0.69	$54,957	$0	0.00%
9	Energy Charge							
10	Summer							
11	On-Peak	10,986,763	0.047848	$525,695	0.047848	$525,695	$0	0.00%
12	Mid-Peak	18,803,597	0.037752	$709,873	0.037752	$709,873	$0	0.00%
13	Off-Peak	14,380,542	0.033390	$480,166	0.033390	$480,166	$0	0.00%
14	Non-Summer							
15	Mid-Peak	77,285,191	0.035658	$2,755,835	0.035658	$2,755,835	$0	0.00%
16	Off-Peak	57,732,954	0.032292	$1,864,313	0.032292	$1,864,313	$0	0.00%
17	Total Energy	179,189,047		$6,335,882		$6,335,882	$0	0.00%
18	Total Revenue			$8,213,064		$8,213,064	$0	0.00%
19	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
20	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
21	PSA		0.000000	$0	0.000000	$0	$0	0.00%
22	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
23	Total Billed Revenue			$8,213,064		$8,213,064	$0	0.00%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Large Power Service - Transmission
Schedule 19

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge	12	200.00	$2,400	237.00	$2,844	$444	18.50%
2	Minimum Charge	0	10.00	$0	10.00	$0	$0	0.00%
3	Basic Charge (per kW)	165,068	0.30	$49,520	0.34	$56,123	$6,603	13.33%
4	Demand Charge							
5	Summer	52,429	3.59	$188,222	4.98	$261,099	$72,877	38.72%
6	Non-Summer	100,121	3.84	$384,463	4.71	$471,568	$87,105	22.66%
7	Total Demand	152,550		$572,685		$732,667	$159,982	27.94%
8	On-Peak Summer	51,982	0.69	$35,868	0.96	$49,903	$14,035	39.13%
9	Energy Charge							
10	Summer							
11	On-Peak	6,439,218	0.044001	$283,332	0.050816	$327,215	$43,883	15.49%
12	Mid-Peak	12,068,104	0.035013	$422,541	0.040434	$487,962	$65,421	15.48%
13	Off-Peak	10,000,842	0.031110	$311,126	0.035925	$359,280	$48,154	15.48%
14	Non-Summer							
15	Mid-Peak	25,204,122	0.033017	$832,165	0.038230	$963,554	$131,389	15.79%
16	Off-Peak	20,443,581	0.030022	$613,757	0.034760	$710,619	$96,862	15.78%
17	Total Energy	74,155,867		$2,462,921		$2,848,630	$385,709	15.66%
18	Total Revenue			$3,123,394		$3,690,167	$566,773	18.15%
19	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
20	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
21	PSA		0.000000	$0	0.000000	$0	$0	0.00%
22	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
23	Total Billed Revenue			$3,123,394		$3,690,167	$566,773	18.15%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Agricultural Irrigation Service - Secondary
Schedule 24

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge							
2	In-Season	6,478	15.00	$97,176	22.00	$142,525	$45,349	46.67%
3	Out-Season	12,503	3.00	$37,508	3.50	$43,759	$6,251	16.67%
4	Total	18,981		$134,684		$186,284	$51,600	38.31%
5	Minimum Charge	247	3.00	$740	3.00	$740	$0	0.00%
6	Demand Charge							
7	In-Season	106,958	6.05	$647,098	9.00	$962,626	$315,528	48.76%
8	Out-Season	33,431	0.00	$0	0.00	$0	$0	0.00%
9	Total Demand	140,390		$647,098		$962,626	$315,528	48.76%
10	Current Energy Charge							
11	In-Season							
12	First 164 kWh per kW	18,227,779	0.057355	$1,045,454	0.072459	$1,320,767	$275,313	26.33%
13	All Other kWh In-Season	21,363,206	0.055992	$1,196,169	0.068358	$1,460,346	$264,177	22.09%
14	Total In-Season			$2,241,623		$2,781,113	$539,490	24.07%
15	Out-Season	7,058,280	0.060939	$430,125	0.076079	$536,987	$106,862	24.84%
16	Total Energy	46,649,265		$2,671,748		$3,318,100	$646,352	24.19%
17	Total Revenue			$3,454,270		$4,467,750	$1,013,480	29.34%
18	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
19	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
20	PSA		0.000000	$0	0.000000	$0	$0	0.00%
21	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
22	Total Billed Revenue			$3,454,270		$4,467,750	$1,013,480	29.34%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Agricultural Irrigation Service - Transmission
Schedule 24

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge							
2	In-Season	0	128.00	$0	188.00	$0	$0	0.00%
3	Out-Season	0	3.00	$0	3.50	$0	$0	0.00%
4	Total	0		$0		$0	$0	0.00%
5	Minimum Charge	0	3.00	$0	3.00	$0	$0	0.00%
6	Demand Charge							
7	In-Season	0	5.70	$0	8.48	$0	$0	0.00%
8	Out-Season	0	0.00	$0	0.00	$0	$0	0.00%
9	Total Demand	0		$0		$0	$0	0.00%
10	Current Energy Charge							
11	In-Season							
12	First 164 kWh per kW	0	0.055533	$0	0.070157	$0	$0	0.00%
13	All Other kWh In-Season	0	0.054224	$0	0.066200	$0	$0	0.00%
14	Total In-Season			$0		$0	$0	0.00%
15	Out-Season	0	0.058977	$0	0.073629	$0	$0	0.00%
16	Total Energy	0		$0		$0	$0	0.00%
17	Total Revenue			$0		$0	$0	0.00%
18	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
19	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
20	PSA		0.000000	$0	0.000000	$0	$0	0.00%
21	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
22	Total Billed Revenue			$0		$0	$0	0.00%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Unmetered General Service
Schedule 40

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Number of Billings	36						
2	Energy Charge							
3	Total Energy	12,900	0.075250	$971	0.087740	$1,132	$161	16.60%
4	Total Revenue			$971		$1,132	$161	16.60%
5	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
6	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
7	PSA		0.000000	$0	0.000000	$0	$0	0.00%
8	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
9	Total Billed Revenue			$971		$1,132	$161	16.60%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Street Lighting Service
Schedule 41

Summary

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	A - Company-Owned, Non-Metered, Maintenance			120,468		126,266	$5,798	4.81%
2	B - Customer-Owned, Non-Metered, Maintenance			1,265		715	($550)	(43.48)%
3	C - Customer-Owned, Non-Metered, No Maintenance			0		0	$0	0.00%
4	CM - Customer-Owned, Metered, No Maintenance			2,118		1,446	($672)	(31.73)%
5	Total Bills	168						
6	Total kWh	778,108						
7	Total Revenue			$123,851		$128,427	$4,576	3.69%
8	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
9	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
10	PSA		0.000000	$0	0.000000	$0	$0	0.00%
11	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
12	Total Billed Revenue			$123,851		$128,427	$4,576	3.69%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Schedule 41 - Street Lighting Service (cont'd)

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	**A - Company-Owned, Non-Metered, Maintenance**							
2	Sodium Vapor							
3	70 Watt	0	8.38	0	7.85	0	$0	0.00%
4	100 Watt	10,061	8.32	83,708	8.50	85,519	$1,811	2.16%
5	200 Watt	1,983	10.00	19,831	11.47	22,746	$2,915	14.70%
6	250 watt	309	11.04	3,411	12.53	3,872	$461	13.52%
7	400 Watt	986	13.71	13,518	14.33	14,129	$611	4.52%
8	Total Sodium Vapor	13,339		120,468		126,266	$5,798	4.81%
9	A - Company-Owned, Non-Metered, Maintenance			$120,468		$126,266	$5,798	4.81%
10	**B - Customer-Owned, Non-Metered, Maintenance**							
11	Sodium Vapor							
12	70 Watt	0	4.79	0	1.93	0	$0	0.00%
13	100 Watt	12	4.98	60	2.47	30	($30)	(50.00)%
14	200 Watt	148	6.68	989	3.71	549	($440)	(44.49)%
15	250 watt	12	7.70	92	4.65	56	($36)	(39.13)%
16	400 Watt	12	10.37	124	6.70	80	($44)	(35.48)%
17	Total Sodium Vapor	184		1,265		715	($550)	(43.48)%
18	B - Customer-Owned, Non-Metered, Maintenance			$1,265		$715	($550)	(43.48)%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Schedule 41 - Street Lighting Service (cont'd)

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	**C - Customer-Owned, Non-Metered, No Maintenance**							
2	Energy Charge							
3	Per kWh	0	0.050670	$0	0.035865	$0	$0	0.00%
4	C - Customer-Owned, Non-Metered, No Maintenance			$0		$0	$0	0.00%
5	**CM - Customer-Owned, Metered, No Maintenance**							
6	Meter Charge	19	8.00	152	2.90	55	($97)	(63.82)%
7	Energy Charge							
8	per kWh	38,795	0.050670	1,966	0.035865	1,391	($575)	(29.25)%
9	CM - Customer-Owned, Metered, No Maintenance			$2,118		$1,446	($672)	(31.73)%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
2011 General Rate Case Filing
Filed July 29, 2011

Traffic Control Signal Lighting Service
Schedule 42

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Number of Billings	72						
2	Energy Charge							
3	Total Energy	16,328	0.075380	$1,231	0.097500	$1,592	$361	29.34%
4	Total Revenue			$1,231		$1,592	$361	29.34%
5	Solar PV Pilot Program Rider		0.00%	$0	0.00%	$0	$0	0.00%
5	Energy Efficiency Rider		0.00%	$0	0.00%	$0	$0	0.00%
6	PSA		0.000000	$0	0.000000	$0	$0	0.00%
7	APCU - March Forecast		0.000000	$0	0.000000	$0	$0	0.00%
8	Total Billed Revenue			$1,231		$1,592	$361	29.34%

Idaho Power/1202
Witness: Scott D. Sparks

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Typical Monthly Billing Comparison

July 29, 2011

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 7, Small General Service - Single Phase

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Summer			Non-Summer			Avg Mth Cost -12 Mths		
Line No	Energy kWh	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference
1	100	15.08	16.65	10.46%	15.08	16.65	10.46%	15.08	16.65	10.41%
2	200	21.56	23.31	8.13%	21.56	23.31	8.13%	21.56	23.31	8.12%
3	300	28.03	29.96	6.88%	28.03	29.96	6.88%	28.03	29.96	6.89%
4	400	36.61	39.06	6.70%	35.31	37.38	5.84%	35.64	37.80	6.06%
5	500	45.19	48.17	6.59%	42.60	44.79	5.16%	43.24	45.64	5.55%
6	600	53.77	57.27	6.52%	49.88	52.21	4.67%	50.85	53.47	5.15%
7	700	62.34	66.37	6.46%	57.16	59.62	4.31%	58.46	61.31	4.88%
8	800	70.92	75.48	6.42%	64.44	67.04	4.03%	66.06	69.15	4.68%
9	900	79.50	84.58	6.39%	71.72	74.46	3.81%	73.67	76.99	4.51%
10	1,000	88.08	93.68	6.36%	79.01	81.87	3.63%	81.27	84.82	4.37%
11	1,100	96.65	102.78	6.34%	86.29	89.29	3.47%	88.88	92.66	4.25%
12	1,200	105.23	111.89	6.32%	93.57	96.70	3.35%	96.48	100.50	4.17%
13	1,300	113.81	120.99	6.31%	100.85	104.12	3.24%	104.09	108.33	4.07%
14	1,400	122.39	130.09	6.30%	108.13	111.53	3.14%	111.70	116.17	4.00%
15	1,500	130.96	139.19	6.28%	115.42	118.95	3.06%	119.30	124.01	3.95%
16	2,000	173.85	184.71	6.24%	151.82	156.03	2.77%	157.33	163.20	3.73%
17	2,500	216.74	230.22	6.22%	188.23	193.10	2.59%	195.36	202.38	3.59%
18	3,000	259.63	275.73	6.20%	224.64	230.18	2.46%	233.39	241.57	3.50%
19	4,000	345.40	366.76	6.18%	297.46	304.34	2.31%	309.45	319.94	3.39%
20	5,000	431.18	457.78	6.17%	370.28	378.49	2.22%	385.51	398.31	3.32%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 9, Large General Service - Secondary, Single Phase
Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	11	20%	1,440	131.54	152.77	21.23	16.14%
2			35%	2,520	182.20	207.68	25.48	13.98%
3			50%	3,600	232.85	262.59	29.74	12.77%
4			65%	4,680	283.51	317.50	33.99	11.99%
5			80%	5,760	334.17	372.42	38.25	11.45%
6	50	57	20%	7,200	620.71	721.33	100.62	16.21%
7			35%	12,600	873.99	995.90	121.91	13.95%
8			50%	18,000	1,127.27	1,270.46	143.19	12.70%
9			65%	23,400	1,380.55	1,545.02	164.47	11.91%
10			80%	28,800	1,633.84	1,819.59	185.75	11.37%
11	100	114	20%	14,400	1,231.92	1,431.67	199.75	16.21%
12			35%	25,200	1,738.48	1,980.79	242.31	13.94%
13			50%	36,000	2,245.04	2,529.92	284.88	12.69%
14			65%	46,800	2,751.61	3,079.05	327.44	11.90%
15			80%	57,600	3,258.17	3,628.17	370.00	11.36%
16	300	342	20%	43,200	3,676.75	4,273.00	596.25	16.22%
17			35%	75,600	5,196.44	5,920.38	723.94	13.93%
18			50%	108,000	6,716.13	7,567.76	851.63	12.68%
19			65%	140,400	8,235.82	9,215.14	979.32	11.89%
20			80%	172,800	9,755.51	10,862.52	1,107.01	11.35%
21	500	570	20%	72,000	6,121.59	7,114.34	992.75	16.22%
22			35%	126,000	8,654.40	9,859.97	1,205.57	13.93%
23			50%	180,000	11,187.22	12,605.60	1,418.38	12.68%
24			65%	234,000	13,720.04	15,351.23	1,631.19	11.89%
25			80%	288,000	16,252.85	18,096.86	1,844.01	11.35%
26	750	855	20%	108,000	9,177.63	10,666.01	1,488.38	16.22%
27			35%	189,000	12,976.86	14,784.46	1,807.60	13.93%
28			50%	270,000	16,776.08	18,902.90	2,126.82	12.68%
29			65%	351,000	20,575.30	23,021.35	2,446.05	11.89%
30			80%	432,000	24,374.53	27,139.79	2,765.26	11.34%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 9, Large General Service - Secondary, Single Phase
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	10	11	20%	1,440	118.13	131.74	13.61	11.52%
2			35%	2,520	164.57	182.13	17.56	10.67%
3			50%	3,600	211.02	232.52	21.50	10.19%
4			65%	4,680	257.46	282.91	25.45	9.89%
5			80%	5,760	303.91	333.30	29.39	9.67%
6	50	57	20%	7,200	553.64	616.19	62.55	11.30%
7			35%	12,600	785.86	868.14	82.28	10.47%
8			50%	18,000	1,018.09	1,120.09	102.00	10.02%
9			65%	23,400	1,250.32	1,372.05	121.73	9.74%
10			80%	28,800	1,482.54	1,624.00	141.46	9.54%
11	100	114	20%	14,400	1,097.77	1,221.38	123.61	11.26%
12			35%	25,200	1,562.23	1,725.28	163.05	10.44%
13			50%	36,000	2,026.68	2,229.19	202.51	9.99%
14			65%	46,800	2,491.13	2,733.09	241.96	9.71%
15			80%	57,600	2,955.59	3,237.00	281.41	9.52%
16	300	342	20%	43,200	3,274.32	3,642.13	367.81	11.23%
17			35%	75,600	4,667.68	5,153.84	486.16	10.42%
18			50%	108,000	6,061.04	6,665.56	604.52	9.97%
19			65%	140,400	7,454.40	8,177.28	722.88	9.70%
20			80%	172,800	8,847.76	9,689.00	841.24	9.51%
21	500	570	20%	72,000	5,450.86	6,062.88	612.02	11.23%
22			35%	126,000	7,773.13	8,582.41	809.28	10.41%
23			50%	180,000	10,095.40	11,101.94	1,006.54	9.97%
24			65%	234,000	12,417.67	13,621.47	1,203.80	9.69%
25			80%	288,000	14,739.94	16,141.00	1,401.06	9.51%
26	750	855	20%	108,000	8,171.54	9,088.81	917.27	11.23%
27			35%	189,000	11,654.95	12,868.11	1,213.16	10.41%
28			50%	270,000	15,138.35	16,647.41	1,509.06	9.97%
29			65%	351,000	18,621.76	20,426.71	1,804.95	9.69%
30			80%	432,000	22,105.16	24,206.01	2,100.85	9.50%

Idaho Power Company
Typical Monthly Billing Comparison
State of Idaho
General Rate Case
Filed June 1, 2011
Schedule 9, Large General Service - Secondary
Weighted Monthly Average

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	11	20%	1,440	121.48	137.00	15.52	12.78%
2			35%	2,520	168.98	188.52	19.54	11.56%
3			50%	3,600	216.48	240.04	23.56	10.88%
4			65%	4,680	263.97	291.56	27.59	10.45%
5			80%	5,760	311.48	343.08	31.60	10.15%
6	50	57	20%	7,200	570.41	642.48	72.07	12.63%
7			35%	12,600	807.89	900.08	92.19	11.41%
8			50%	18,000	1,045.39	1,157.68	112.29	10.74%
9			65%	23,400	1,282.88	1,415.29	132.41	10.32%
10			80%	28,800	1,520.37	1,672.90	152.53	10.03%
11	100	114	20%	14,400	1,131.31	1,273.95	142.64	12.61%
12			35%	25,200	1,606.29	1,789.16	182.87	11.38%
13			50%	36,000	2,081.27	2,304.37	223.10	10.72%
14			65%	46,800	2,556.25	2,819.58	263.33	10.30%
15			80%	57,600	3,031.24	3,334.79	303.55	10.01%
16	300	342	20%	43,200	3,374.93	3,799.85	424.92	12.59%
17			35%	75,600	4,799.87	5,345.48	545.61	11.37%
18			50%	108,000	6,224.81	6,891.11	666.30	10.70%
19			65%	140,400	7,649.76	8,436.75	786.99	10.29%
20			80%	172,800	9,074.70	9,982.38	907.68	10.00%
21	500	570	20%	72,000	5,618.54	6,325.75	707.21	12.59%
22			35%	126,000	7,993.45	8,901.80	908.35	11.36%
23			50%	180,000	10,368.36	11,477.86	1,109.50	10.70%
24			65%	234,000	12,743.26	14,053.91	1,310.65	10.29%
25			80%	288,000	15,118.17	16,629.97	1,511.80	10.00%
26	750	855	20%	108,000	8,423.06	9,483.11	1,060.05	12.59%
27			35%	189,000	11,985.43	13,347.20	1,361.77	11.36%
28			50%	270,000	15,547.78	17,211.28	1,663.50	10.70%
29			65%	351,000	19,110.15	21,075.37	1,965.22	10.28%
30			80%	432,000	22,672.50	24,939.46	2,266.96	10.00%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 9, Large General Service - Primary
Summer

Line No	Demand kW	On-Peak Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	400	358	460	40%	115,200	7,637.36	8,290.13	652.78	8.55%
2				50%	144,000	8,853.33	9,541.90	688.57	7.78%
3				60%	172,800	10,069.30	10,793.67	724.37	7.19%
4				70%	201,600	11,285.26	12,045.43	760.17	6.74%
5				80%	230,400	12,501.23	13,297.20	795.96	6.37%
6	500	448	575	40%	144,000	9,496.70	10,310.92	814.22	8.57%
7				50%	180,000	11,016.66	11,875.62	858.97	7.80%
8				60%	216,000	12,536.62	13,440.33	903.71	7.21%
9				70%	252,000	14,056.58	15,005.04	948.46	6.75%
10				80%	288,000	15,576.54	16,569.75	993.20	6.38%
11	600	538	690	40%	172,800	11,356.04	12,331.70	975.66	8.59%
12				50%	216,000	13,179.99	14,209.35	1,029.36	7.81%
13				60%	259,200	15,003.94	16,087.00	1,083.05	7.22%
14				70%	302,400	16,827.90	17,964.65	1,136.75	6.76%
15				80%	345,600	18,651.85	19,842.29	1,190.45	6.38%
16	700	627	805	40%	201,600	13,215.38	14,352.48	1,137.11	8.60%
17				50%	252,000	15,343.32	16,543.07	1,199.75	7.82%
18				60%	302,400	17,471.27	18,733.66	1,262.40	7.23%
19				70%	352,800	19,599.21	20,924.25	1,325.04	6.76%
20				80%	403,200	21,727.16	23,114.84	1,387.69	6.39%
21	800	717	920	40%	230,400	15,074.72	16,373.27	1,298.55	8.61%
22				50%	288,000	17,506.65	18,876.80	1,370.15	7.83%
23				60%	345,600	19,938.59	21,380.33	1,441.74	7.23%
24				70%	403,200	22,370.53	23,883.86	1,513.33	6.76%
25				80%	460,800	24,802.47	26,387.39	1,584.93	6.39%
26	900	806	1,035	40%	259,200	16,934.05	18,394.05	1,460.00	8.62%
27				50%	324,000	19,669.98	21,210.52	1,540.54	7.83%
28				60%	388,800	22,405.91	24,027.00	1,621.08	7.24%
29				70%	453,600	25,141.84	26,843.47	1,701.62	6.77%
30				80%	518,400	27,877.77	29,659.94	1,782.17	6.39%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 9, Large General Service - Primary
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	400	503	40%	115,200	2,427.64	2,627.18	199.54	8.22%
2			50%	144,000	2,427.64	2,627.18	199.54	8.22%
3			60%	172,800	2,427.64	2,627.18	199.54	8.22%
4			70%	201,600	2,427.64	2,627.18	199.54	8.22%
5			80%	230,400	2,427.64	2,627.18	199.54	8.22%
6	500	628	40%	144,000	2,984.55	3,232.23	247.68	8.30%
7			50%	180,000	2,984.55	3,232.23	247.68	8.30%
8			60%	216,000	2,984.55	3,232.23	247.68	8.30%
9			70%	252,000	2,984.55	3,232.23	247.68	8.30%
10			80%	288,000	2,984.55	3,232.23	247.68	8.30%
11	600	754	40%	172,800	3,541.46	3,837.27	295.82	8.35%
12			50%	216,000	3,541.46	3,837.27	295.82	8.35%
13			60%	259,200	3,541.46	3,837.27	295.82	8.35%
14			70%	302,400	3,541.46	3,837.27	295.82	8.35%
15			80%	345,600	3,541.46	3,837.27	295.82	8.35%
16	700	880	40%	201,600	4,098.37	4,442.32	343.95	8.39%
17			50%	252,000	4,098.37	4,442.32	343.95	8.39%
18			60%	302,400	4,098.37	4,442.32	343.95	8.39%
19			70%	352,800	4,098.37	4,442.32	343.95	8.39%
20			80%	403,200	4,098.37	4,442.32	343.95	8.39%
21	800	1,005	40%	230,400	4,655.28	5,047.36	392.09	8.42%
22			50%	288,000	4,655.28	5,047.36	392.09	8.42%
23			60%	345,600	4,655.28	5,047.36	392.09	8.42%
24			70%	403,200	4,655.28	5,047.36	392.09	8.42%
25			80%	460,800	4,655.28	5,047.36	392.09	8.42%
26	900	1,131	40%	259,200	5,212.19	5,652.41	440.22	8.45%
27			50%	324,000	5,212.19	5,652.41	440.22	8.45%
28			60%	388,800	5,212.19	5,652.41	440.22	8.45%
29			70%	453,600	5,212.19	5,652.41	440.22	8.45%
30			80%	518,400	5,212.19	5,652.41	440.22	8.45%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 9, Large General Service - Primary
Weighted Monthly Average

Line No	Demand kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	400	50%	144,000	3,730.07	4,042.92	312.85	8.39%
2		60%	172,800	4,034.06	4,355.86	321.80	7.98%
3		70%	201,600	4,338.05	4,668.80	330.75	7.62%
4		80%	230,400	4,642.04	4,981.74	339.70	7.32%
5		90%	259,200	4,946.04	5,294.69	348.65	7.05%
6	500	50%	180,000	4,612.59	5,001.90	389.32	8.44%
7		60%	216,000	4,992.58	5,393.08	400.50	8.02%
8		70%	252,000	5,372.57	5,784.25	411.69	7.66%
9		80%	288,000	5,752.56	6,175.43	422.87	7.35%
10		90%	324,000	6,132.55	6,566.61	434.06	7.08%
11	600	50%	216,000	5,495.10	5,960.88	465.78	8.48%
12		60%	259,200	5,951.09	6,430.29	479.20	8.05%
13		70%	302,400	6,407.08	6,899.70	492.63	7.69%
14		80%	345,600	6,863.07	7,369.12	506.05	7.37%
15		90%	388,800	7,319.06	7,838.53	519.47	7.10%
16	700	50%	252,000	6,377.62	6,919.86	542.24	8.50%
17		60%	302,400	6,909.61	7,467.51	557.90	8.07%
18		70%	352,800	7,441.59	8,015.16	573.56	7.71%
19		80%	403,200	7,973.58	8,562.80	589.22	7.39%
20		90%	453,600	8,505.56	9,110.45	604.89	7.11%
21	800	50%	288,000	7,260.14	7,878.84	618.70	8.52%
22		60%	345,600	7,868.12	8,504.72	636.60	8.09%
23		70%	403,200	8,476.11	9,130.61	654.50	7.72%
24		80%	460,800	9,084.09	9,756.49	672.40	7.40%
25		90%	518,400	9,692.07	10,382.37	690.30	7.12%
26	900	50%	324,000	8,142.65	8,837.82	695.17	8.54%
27		60%	388,800	8,826.64	9,541.94	715.30	8.10%
28		70%	453,600	9,510.62	10,246.06	735.44	7.73%
29		80%	518,400	10,194.60	10,950.18	755.57	7.41%
30		90%	583,200	10,878.58	11,654.29	775.71	7.13%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 19, Large Power Service - Transmission
Summer

Line No	Demand kW	On-Peak Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	1,000	917	1,100	50%	360,000	17,595.58	21,302.64	3,707.06	21.07%
2				60%	432,000	20,164.11	24,268.84	4,104.74	20.36%
3				70%	504,000	22,732.63	27,235.04	4,502.41	19.81%
4				80%	576,000	25,301.16	30,201.24	4,900.09	19.37%
5				90%	648,000	27,869.68	33,167.44	5,297.76	19.01%
6	2,500	2,293	2,750	50%	900,000	43,688.95	52,901.11	9,212.16	21.09%
7				60%	1,080,000	50,110.26	60,316.61	10,206.34	20.37%
8				70%	1,260,000	56,531.58	67,732.11	11,200.53	19.81%
9				80%	1,440,000	62,952.89	75,147.60	12,194.72	19.37%
10				90%	1,620,000	69,374.20	82,563.10	13,188.90	19.01%
11	4,000	3,670	4,399	50%	1,440,000	69,782.32	84,499.57	14,717.25	21.09%
12				60%	1,728,000	80,056.42	96,364.37	16,307.95	20.37%
13				70%	2,016,000	90,330.52	108,229.17	17,898.65	19.81%
14				80%	2,304,000	100,604.62	120,093.97	19,489.35	19.37%
15				90%	2,592,000	110,878.72	131,958.77	21,080.05	19.01%
16	5,500	5,046	6,049	50%	1,980,000	95,875.69	116,098.04	20,222.34	21.09%
17				60%	2,376,000	110,002.58	132,412.14	22,409.55	20.37%
18				70%	2,772,000	124,129.47	148,726.23	24,596.77	19.82%
19				80%	3,168,000	138,256.35	165,040.33	26,783.98	19.37%
20				90%	3,564,000	152,383.24	181,354.43	28,971.19	19.01%
21	7,000	6,422	7,699	50%	2,520,000	121,969.07	147,696.50	25,727.44	21.09%
22				60%	3,024,000	139,948.74	168,459.90	28,511.16	20.37%
23				70%	3,528,000	157,928.41	189,223.30	31,294.88	19.82%
24				80%	4,032,000	175,908.09	209,986.69	34,078.61	19.37%
25				90%	4,536,000	193,887.76	230,750.09	36,862.33	19.01%
26	8,500	7,798	9,349	50%	3,060,000	148,062.44	179,294.97	31,232.53	21.09%
27				60%	3,672,000	169,894.90	204,507.66	34,612.77	20.37%
28				70%	4,284,000	191,727.36	229,720.36	37,993.00	19.82%
29				80%	4,896,000	213,559.82	254,933.06	41,373.24	19.37%
30				90%	5,508,000	235,392.28	280,145.75	44,753.47	19.01%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 19, Large Power Service - Transmission
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	1,000	1,171	50%	360,000	16,983.78	20,445.97	3,462.19	20.39%
2			60%	432,000	19,552.30	23,412.17	3,859.87	19.74%
3			70%	504,000	22,120.83	26,378.37	4,257.54	19.25%
4			80%	576,000	24,689.35	29,344.57	4,655.22	18.86%
5			90%	648,000	27,257.88	32,310.77	5,052.89	18.54%
6	2,500	2,926	50%	900,000	42,159.44	50,759.43	8,599.98	20.40%
7			60%	1,080,000	48,580.76	58,174.93	9,594.17	19.75%
8			70%	1,260,000	55,002.07	65,590.43	10,588.36	19.25%
9			80%	1,440,000	61,423.38	73,005.93	11,582.55	18.86%
10			90%	1,620,000	67,844.69	80,421.42	12,576.73	18.54%
11	4,000	4,682	50%	1,440,000	67,335.11	81,072.89	13,737.78	20.40%
12			60%	1,728,000	77,609.21	92,937.68	15,328.47	19.75%
13			70%	2,016,000	87,883.31	104,802.48	16,919.17	19.25%
14			80%	2,304,000	98,157.41	116,667.28	18,509.87	18.86%
15			90%	2,592,000	108,431.51	128,532.08	20,100.57	18.54%
16	5,500	6,438	50%	1,980,000	92,510.78	111,386.34	18,875.57	20.40%
17			60%	2,376,000	106,637.66	127,700.44	21,062.78	19.75%
18			70%	2,772,000	120,764.55	144,014.54	23,249.99	19.25%
19			80%	3,168,000	134,891.44	160,328.64	25,437.20	18.86%
20			90%	3,564,000	149,018.32	176,642.73	27,624.41	18.54%
21	7,000	8,194	50%	2,520,000	117,686.44	141,699.80	24,013.36	20.40%
22			60%	3,024,000	135,666.12	162,463.20	26,797.08	19.75%
23			70%	3,528,000	153,645.79	183,226.59	29,580.80	19.25%
24			80%	4,032,000	171,625.46	203,989.99	32,364.53	18.86%
25			90%	4,536,000	189,605.14	224,753.39	35,148.25	18.54%
26	8,500	9,949	50%	3,060,000	142,862.11	172,013.26	29,151.15	20.41%
27			60%	3,672,000	164,694.57	197,225.95	32,531.38	19.75%
28			70%	4,284,000	186,527.03	222,438.65	35,911.62	19.25%
29			80%	4,896,000	208,359.49	247,651.35	39,291.85	18.86%
30			90%	5,508,000	230,191.95	272,864.04	42,672.09	18.54%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 29, 2011
Schedule 19, Large Power Service - Transmission
Weighted Average Monthly

Line No	Demand kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	1,000	50%	360,000	17,136.73	20,660.14	3,523.41	20.56%
2		60%	432,000	19,705.25	23,626.34	3,921.09	19.90%
3		70%	504,000	22,273.78	26,592.54	4,318.76	19.39%
4		80%	576,000	24,842.30	29,558.74	4,716.44	18.99%
5		90%	648,000	27,410.83	32,524.94	5,114.11	18.66%
6	2,500	50%	900,000	42,541.82	51,294.85	8,753.03	20.58%
7		60%	1,080,000	48,963.13	58,710.35	9,747.21	19.91%
8		70%	1,260,000	55,384.44	66,125.85	10,741.40	19.39%
9		80%	1,440,000	61,805.76	73,541.35	11,735.59	18.99%
10		90%	1,620,000	68,227.07	80,956.84	12,729.77	18.66%
11	4,000	50%	1,440,000	67,946.91	81,929.56	13,982.64	20.58%
12		60%	1,728,000	78,221.01	93,794.36	15,573.34	19.91%
13		70%	2,016,000	88,495.11	105,659.15	17,164.04	19.40%
14		80%	2,304,000	98,769.21	117,523.95	18,754.74	18.99%
15		90%	2,592,000	109,043.31	129,388.75	20,345.44	18.66%
16	5,500	50%	1,980,000	93,352.00	112,564.27	19,212.26	20.58%
17		60%	2,376,000	107,478.89	128,878.36	21,399.47	19.91%
18		70%	2,772,000	121,605.78	145,192.46	23,586.68	19.40%
19		80%	3,168,000	135,732.67	161,506.56	25,773.89	18.99%
20		90%	3,564,000	149,859.55	177,820.66	27,961.10	18.66%
21	7,000	50%	2,520,000	118,757.10	143,198.97	24,441.88	20.58%
22		60%	3,024,000	136,736.77	163,962.37	27,225.60	19.91%
23		70%	3,528,000	154,716.45	184,725.77	30,009.32	19.40%
24		80%	4,032,000	172,696.12	205,489.17	32,793.05	18.99%
25		90%	4,536,000	190,675.79	226,252.56	35,576.77	18.66%
26	8,500	50%	3,060,000	144,162.19	173,833.68	29,671.49	20.58%
27		60%	3,672,000	165,994.65	199,046.38	33,051.73	19.91%
28		70%	4,284,000	187,827.11	224,259.08	36,431.96	19.40%
29		80%	4,896,000	209,659.57	249,471.77	39,812.20	18.99%
30		90%	5,508,000	231,492.03	274,684.47	43,192.43	18.66%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed June 1, 2011
Schedule 24, Agricultural Irrigation Service - Secondary
In-Season

Line No	Demand kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	20%	1,440	$158.09	$216.34	$58.25	36.85%
2		35%	2,520	$218.83	$290.99	$72.16	32.98%
3		50%	3,600	$279.30	$364.81	$85.51	30.62%
4		65%	4,680	$339.78	$438.64	$98.86	29.10%
5		80%	5,760	$400.25	$512.46	$112.21	28.03%
6	50	20%	7,200	$731.82	$997.80	$265.98	36.35%
7		35%	12,600	$1,034.17	$1,366.94	$332.77	32.18%
8		50%	18,000	$1,336.53	$1,736.07	$399.54	29.89%
9		65%	23,400	$1,638.89	$2,105.20	$466.31	28.45%
10		80%	28,800	$1,941.25	$2,474.33	$533.08	27.46%
11	100	20%	14,400	$1,448.64	$1,973.61	$524.97	36.24%
12		35%	25,200	$2,053.35	$2,711.88	$658.53	32.07%
13		50%	36,000	$2,658.06	$3,450.15	$792.09	29.80%
14		65%	46,800	$3,262.78	$4,188.41	$925.63	28.37%
15		80%	57,600	$3,867.49	$4,926.68	$1,059.19	27.39%
16	300	20%	43,200	$4,315.92	$5,876.83	$1,560.91	36.17%
17		35%	75,600	$6,130.06	$8,091.63	$1,961.57	32.00%
18		50%	108,000	$7,944.20	$10,306.43	$2,362.23	29.74%
19		65%	140,400	$9,758.34	$12,521.23	$2,762.89	28.31%
20		80%	172,800	$11,572.48	$14,736.03	$3,163.55	27.34%
21	500	20%	72,000	$7,183.19	$9,780.06	$2,596.87	36.15%
22		35%	126,000	$10,206.76	$13,471.39	$3,264.63	31.98%
23		50%	180,000	$13,230.33	$17,162.72	$3,932.39	29.72%
24		65%	234,000	$16,253.89	$20,854.06	$4,600.17	28.30%
25		80%	288,000	$19,277.46	$24,545.39	$5,267.93	27.33%
26	750	20%	108,000	$10,767.29	$14,659.09	3,891.80	36.14%
27		35%	189,000	$15,302.64	$20,196.09	4,893.45	31.98%
28		50%	270,000	$19,837.99	$25,733.09	5,895.10	29.72%
29		65%	351,000	$24,373.35	$31,270.08	6,896.73	28.30%
30		80%	432,000	$28,908.70	$36,807.08	7,898.38	27.32%

In-season months include June, July, August, September

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed June 1, 2011
Schedule 24, Agricultural Irrigation Service - Secondary
Out-of-Season

Line No	Demand kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	10	20%	1,440	$90.75	$113.05	22.30	24.57%
2		35%	2,520	$156.57	$195.22	38.65	24.69%
3		50%	3,600	$222.38	$277.38	55.00	24.73%
4		65%	4,680	$288.19	$359.55	71.36	24.76%
5		80%	5,760	$354.01	$441.72	87.71	24.78%
6	50	20%	7,200	$441.76	$551.27	109.51	24.79%
7		35%	12,600	$770.83	$962.10	191.27	24.81%
8		50%	18,000	$1,099.90	$1,372.92	273.02	24.82%
9		65%	23,400	$1,428.97	$1,783.75	354.78	24.83%
10		80%	28,800	$1,758.04	$2,194.58	436.54	24.83%
11	100	20%	14,400	$880.52	$1,099.04	218.52	24.82%
12		35%	25,200	$1,538.66	$1,920.69	382.03	24.83%
13		50%	36,000	$2,196.80	$2,742.34	545.54	24.83%
14		65%	46,800	$2,854.95	$3,564.00	709.05	24.84%
15		80%	57,600	$3,513.09	$4,385.65	872.56	24.84%
16	300	20%	43,200	$2,635.56	$3,290.11	654.55	24.84%
17		35%	75,600	$4,609.99	$5,755.07	1,145.08	24.84%
18		50%	108,000	$6,584.41	$8,220.03	1,635.62	24.84%
19		65%	140,400	$8,558.84	$10,684.99	2,126.15	24.84%
20		80%	172,800	$10,533.26	$13,149.95	2,616.69	24.84%
21	500	20%	72,000	$4,390.61	$5,481.19	1,090.58	24.84%
22		35%	126,000	$7,681.31	$9,589.45	1,908.14	24.84%
23		50%	180,000	$10,972.02	$13,697.72	2,725.70	24.84%
24		65%	234,000	$14,262.73	$17,805.99	3,543.26	24.84%
25		80%	288,000	$17,553.43	$21,914.25	4,360.82	24.84%
26	750	20%	108,000	$6,584.41	$8,220.03	1,635.62	24.84%
27		35%	189,000	$11,520.47	$14,382.43	2,861.96	24.84%
28		50%	270,000	$16,456.53	$20,544.83	4,088.30	24.84%
29		65%	351,000	$21,392.59	$26,707.23	5,314.64	24.84%
30		80%	432,000	$26,328.65	$32,869.63	6,540.98	24.84%

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed June 1, 2011
Schedule 24, Agricultural Irrigation Service - Secondary
Weighted Average Monthly

Line No	Demand kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	20%	1,440	113.20	147.48	34.28	30.29%
2		35%	2,520	177.32	227.14	49.82	28.10%
3		50%	3,600	241.35	306.52	65.17	27.00%
4		65%	4,680	305.39	385.91	80.53	26.37%
5		80%	5,760	369.42	465.30	95.88	25.95%
6	50	20%	7,200	538.45	700.11	161.67	30.02%
7		35%	12,600	858.61	1,097.05	238.44	27.77%
8		50%	18,000	1,178.78	1,493.97	315.19	26.74%
9		65%	23,400	1,498.94	1,890.90	391.96	26.15%
10		80%	28,800	1,819.11	2,287.83	468.72	25.77%
11	100	20%	14,400	1,069.89	1,390.56	320.67	29.97%
12		35%	25,200	1,710.22	2,184.42	474.20	27.73%
13		50%	36,000	2,350.55	2,978.28	627.72	26.71%
14		65%	46,800	2,990.89	3,772.14	781.24	26.12%
15		80%	57,600	3,631.22	4,565.99	934.77	25.74%
16	300	20%	43,200	3,195.68	4,152.35	956.67	29.94%
17		35%	75,600	5,116.68	6,533.92	1,417.24	27.70%
18		50%	108,000	7,037.67	8,915.50	1,877.82	26.68%
19		65%	140,400	8,958.67	11,297.07	2,338.40	26.10%
20		80%	172,800	10,879.67	13,678.64	2,798.98	25.73%
21	500	20%	72,000	5,321.47	6,914.15	1,592.68	29.93%
22		35%	126,000	8,523.13	10,883.43	2,360.30	27.69%
23		50%	180,000	11,724.79	14,852.72	3,127.93	26.68%
24		65%	234,000	14,926.45	18,822.01	3,895.56	26.10%
25		80%	288,000	18,128.11	22,791.30	4,663.19	25.72%
26	750	20%	108,000	7,978.70	10,366.38	2,387.68	29.93%
27		35%	189,000	12,781.19	16,320.32	3,539.12	27.69%
28		50%	270,000	17,583.68	22,274.25	4,690.57	26.68%
29		65%	351,000	22,386.18	28,228.18	5,842.00	26.10%
30		80%	432,000	27,188.67	34,182.11	6,993.45	25.72%