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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

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 a 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. Matthew T. Larkin, Ms. Kelley Noe, and Mr. Douglas N. Jones 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?

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 a 2011 test year based upon 2010 actual financial data in a manner similar to that approved by the Idaho Public Utilities Commission ("Commission") in the Company's last general rate case, IPC-E-08-10 ("2008 Rate Case"), Order Nos. 30722 and 30754. However, Mr. Said instructed me to deviate from the methodology used in the 2008 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 and other Power Cost Adjustment ("PCA") accounts to 2010 levels approved by Order No. 31042 with adjustments to recognize revenues from Hoku Materials, Inc. ("Hoku") and projected demand response incentive payments. Third, Mr. Said asked that the level of recovery of Allowance for Funds Used During Construction ("AFUDC") associated with the Hells Canyon relicensing project construction work in progress ("CWIP") not be increased above the level approved in the Company's 2008 Rate Case. Each of Mr. Said's instructions to deviate from the methodology used in the

2008 Rate Case has the effect of reducing the Company's revenue requirement request in this case.

Mr. Said also directed me to set the 2011 test year pension expense at $17.2 million, the level currently approved for recovery in Case No. IPC-E-11-04, Order No. 32248.

Q. Will you briefly summarize how the Company has developed its 2011 test year ("2011 Test Year" or "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. 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 Year 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 existing regulatory commission orders.

Q. How does the forecast methodology used in this case differ from that applied in the 2008 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 2008 Rate Case is the utilization of growth rates to escalate O&M expenses. In the 2008 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 No. 19 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 No. 20, 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 Idaho 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 No. 20).

A. The major areas or groupings of financial accounts addressed in Exhibit No. 20 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 No. 20.

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 2010 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 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 No. 20.

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 PCA expense accounts were held to the currently approved 2010 normalized levels with adjustments to recognize normalized revenues from Hoku and projected base level demand response incentive payments, which I will describe in greater detail later in my testimony. The PCA expense accounts include Fuel Expense (Accounts 501 and

547), Water for Power Expense (Account 536.002), Purchased Power Expense (Account 555 - excluding purchased power for transmission losses), and Transmission of Electricity by Others (Account 565).

The remaining O&M adjustments were also made in accordance with Mr. Said's instructions. The Idaho 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 approved in the 2008 Rate Case, Order No. 30722. Incentive expense represents the "at-risk" portion of employees' total compensation package. Pension Expense (Account 926) for the Idaho jurisdiction was held to the level approved by the Commission in Case No. IPC-E-11-04, Order No. 32248. 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. 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 acts as 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. This method is similar to that utilized by the Commission Staff in the 2008 Rate Case to validate the Company's labor forecast as additional actual labor cost data became available throughout the test period. A more detailed discussion of the labor-related O&M adjustment is provided in Exhibit No. 20, 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
- North American Electric Reliability Corporation Required Light Data and Ranging Surveys
- 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 No. 20, 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. 30639 were used for the entire 2011 Test Year. The determination of the Depreciation and Amortization Expense adjustments is detailed in Exhibit No. 20, page 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 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 No. 20, pages 28-29.

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, were 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.

Q. Please provide an overview of the methodology to forecast 2011 AFUDC associated with Hells Canyon relicensing CWIP.

A. While AFUDC continues to increase relating to the Hells Canyon relicensing efforts, the Company is requesting recovery of the same amount ($6,815,472) previously included in the 2008 Rate Case and subsequently approved in Order No. 30722. This adjustment is explained in greater detail in Exhibit No. 20, page 27.

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. 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 approved by the Commission in the 2008 Rate Case, Order No. 30722. 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. As mentioned earlier in my testimony, Mr. Said directed me to hold the PCA expense accounts to the currently approved 2010 normalized levels with adjustments to recognize normalized revenues from Hoku and projected base level demand response incentive payments. Consistent with this directive, I developed the adjusted 2010 PCA components shown on Exhibit No. 21. As can be seen on Exhibit No. 21, each of the PCA components is consistent with the currently approved 2010 amount with the exception of Account 442, Hoku First Block Energy Revenues; Account 555, PURPA; and Account 555, Demand Response Incentives. The adjusted PCA expense amounts shown in column "D" of Exhibit No. 21 were provided to Ms. Noe for use in the Idaho jurisdictional revenue requirement determination.

Q. Upon what basis did you make adjustments to Account 442, Hoku First Block Energy Revenues and Account 555, PURPA?

A. Because the 2010 PCA components did not include Hoku First Block Energy Revenues, it was necessary to make an adjustment to increase the PCA-related revenues by $23.9 million in the 2011 Test Year. To not include Hoku First Block Energy Revenues in the 2011 Test Year would improperly understate the Company's expected retail sales revenue. However, to hold the sum of the PCA components to no change as directed by Mr. Said, an offsetting expense adjustment was necessary. Based on a review of the 2011 normalized PCA components developed by Mr. Wright, it was clear that an offsetting adjustment could be justified for PURPA expenses, which Mr. Wright has testified would increase by $50.4 million in 2011. Therefore, Account 555, PURPA was increased by $23.9 million.

Q. How was the adjustment to Account 555, Demand Response Incentives, determined?

A. Under my direction, a forecast for Account 555, Demand Response Incentives, was developed based upon projected fixed incentive levels for the AC Cool Credit, FlexPeak Management, and Irrigation Peak Rewards programs on an Idaho jurisdictional basis. The projected incentive levels for these programs were determined using currently approved fixed incentive amounts and expected participation levels for each program. Because the forecasted amounts were Idaho jurisdictional projections, I instructed Ms. Noe to directly assign them to the Idaho jurisdiction.

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 No. 25 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 Idaho jurisdictional basis?

A. Using the 2011 Test Year financial information, Ms. Noe has calculated the Company's revenue requirement to be $965.2 million on a system-wide basis and $917.6 million on an Idaho 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 $90.6 million on a system-wide basis, and $82.6 million on an Idaho jurisdictional basis. An increase to annual Idaho jurisdictional revenues in the amount of $82.6 million would result in an overall average increase to customer rates of 9.9 percent.

Q. Is it appropriate for the Commission to determine the Company's Idaho jurisdictional revenue requirement to be $917.6 million, its revenue deficiency to be $82.6 million, and therefore, approve an overall 9.9 percent increase to customer rates?

A. Yes. The $917.6 million figure is a reasonable determination of the Company's annual Idaho jurisdictional revenue requirement. The $82.6 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 9.9 percent increase to the Company's Idaho jurisdictional revenues.

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

A. Yes, it does.

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CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 19

IDAHO POWER COMPANY
Methodology Summary - Tatum Exhibit 19
2011 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
	Operations and Maintenance Expenses		
	Power production expenses		
31	Steam power generation(excluding account 501)	500-514	Other Methodology
32	Fuel expense	501	2010 Base

IDAHO POWER COMPANY
Methodology Summary - Tatum Exhibit 19
2011 Test Year

- 2010 Base
- Other Methodology
- Normalized
- Removed in its Entirety

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
33	Hydraulic power generation	535-545	Other Methodology
34	Other power generation(excluding 547)	546-554	Other Methodology
35	Fuel expense	547	2010 Base
	Other power supply expenses		
36	Purchased power (excluding 555.050)	555	2010 Base
37	Transmission Losses	555.050	Other Methodology
38	System control and load dispatch	556	Other Methodology
	Other expenses	557.050	Other Methodology
39	Other expenses - PCA, EPC and PCAM (excluding 557.050)	557	Removed in its entirety
40	Transmission expenses	560-573	Other Methodology
41	Distribution expenses	580-598	Other Methodology
42	Customer account, service and information expenses	901-912	Other Methodology
43	Administrative & general expenses(excluding accts 908.1 and 930.1)	920-935	Other Methodology
44	Energy Efficiency Rider	908.1	Removed in its entirety
45	General Advertising	930.1	Removed in its entirety
	Depreciation and Amortization Expense		
46	Depreciation	403	Other Methodology
47	Amortization	404	Other Methodology
	Electric Plant/Regulatory Assets - Amort, Adj, Gains & Losses		
48	Amortization of electric plant acquisition adjustment-Prairie Power	406	Other Methodology
49	**Regulatory Debits and Credits**	407.3	Other Methodology
	Taxes Other Than Income		
50	Real and personal property	408.1	Other Methodology
51	Kilowatt-hour tax - Idaho	408.1	Normalized
	Licenses		
52	Wyoming	408.1	Other Methodology
53	Shoshone-Bannock	408.1	Other Methodology
	Regulatory commission		
54	Idaho	408.1	2010 Base
55	Oregon	408.1	Other Methodology
56	Franchise tax - Oregon	408.1	Other Methodology
57	**Idaho Energy Resources Statement of Income**	418.1/419	Other Methodology
58	**Financing Costs (AFUDC) Related to Hells Canyon Relicensing**	440-444	2010 Base
	Rate Base Components		
	Electric Plant-In-Service		
59	Projects > $2 million	101	Other Methodology
60	Projects < $2 million	101	2010 Base

IDAHO POWER COMPANY
Methodology Summary - Tatum Exhibit 19
2011 Test Year

- **2010 Base**
- **Other Methodology**
- **Normalized**
- **Removed in its Entirety**

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
	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**	182.3/186.722/186.77	Other Methodology
67	**Plant Held for Future Use(excluding Buhl, Justice, Montour, Peterson Substations)**	105	2010 Base
68	Buhl Substation	105	Other Methodology
	Justice Substation	105	Other Methodology
	Montour Substation	105	Other Methodology
	Peterson Substation Expansion	105	Other Methodology
69	**Deferred Income Taxes**	190/282/283	Other Methodology
70	**Customer Advances For Construction**	252	Other Methodology
71	**IERCO-Subsidiary Rate Base Components**	123.1/186/145	Other Methodology
74	**CWIP - Hells Canyon Relicensing**	107	Other Methodology

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EXHIBIT NO. 20

IDAHO POWER.
An IDACORP Company

Forecast Methodology Manual

2011 Rate Case

Proprietary

TABLE OF CONTENTS

Table of Contents i

Cross-Reference List of Tables iv

Introduction 1

Forecast Methods 2

Cost Of Service Components 3

Forecast Adjustment A—Other Operating Revenues 3

Description 3

Forecast Methodology 3

Forecast Adjustment B & C—Other Revenues and Other Expenses 5

Description 5

Forecast Methodology 5

Forecast Adjustment D—Operations and Maintenance Expenses ("O&M") 5

Overview 5

Labor 5

Non-Labor 6

FERC Account Development 10

Exceptions to the Described O&M Methodology Above 11

Steam Power Generation 12

Description 12

Forecast Methodology 12

Hydraulic Power Generation 12

Description 12

Forecast Methodology 13

Other Power Generation 13

Description 13

Forecast Methodology 13

Transmission Expenses 14

Exhibit No. 20
Case No. IPC-E-11-08
T. Tatum, IPC
Page 2 of 35

Description 14

Forecast Methodology 14

Distribution Expenses 15

Description 15

Forecast Methodology 15

Customer Accounting and Customer Services and Information Expenses 15

Description 15

Forecast Methodology 15

Administration and General Expenses ("A&G") 16

Description 16

Forecast Methodology 16

Forecast Adjustment E—Depreciation and Amortization Expense 18

Description 18

Forecast Methodology 18

Forecast Adjustment F—Electric Plant/Regulatory Assets—Amortization, Adjustments, Gains and Losses 18

Description 18

Forecast Methodology 19

Forecast Adjustment G—Regulatory Debits and Credits 19

Description 19

Forecast Methodology 19

Forecast Adjustment H—Taxes Other than Income Taxes 20

Description 20

Forecast Methodology 20

Real and Personal Property Taxes 20

Idaho kWh Taxes 20

Regulatory Commission Fees 20

Licenses 21

Franchises 21

Forecast Adjustment I—Idaho Energy Resources Co. ("IERCO") Cost of Service Components 21

Description 21

Forecast Methodology 21

Forecast Adjustment J—Allowance for Funds Used During Construction ("AFUDC") Related to Hells Canyon Relicensing 22

Description 22

Forecast Methodology 22

Rate Base Components 23

Forecast Adjustment K—Electric Plant in Service 23

Description 23

Forecast Methodology 23

Plant Additions to Electric Plant In Service 23

Projected 2011 Plant Additions 23

Allocation to FERC Plant Account 24

Retirements from Electric Plant In Service 24

Forecast Adjustments L & M—Accumulated Provision for Depreciation and Amortization 25

Description 25

Forecast Methodology 25

Forecast Adjustment N—Materials and Supplies 26

Description 26

Forecast Methodology 26

Forecast Adjustment O—Other Deferred Programs 27

Description 27

Forecast Methodology 27

Forecast Adjustment P—Plant Held for Future Use 28

Description 28

Forecast Methodology 28

Forecast Adjustment Q—Customer Advances for Construction ("CAC") 28

Description 28

Forecast Methodology 29

Forecast Adjustment R—Idaho Energy Resources Co. ("IERCO") Rate Base 29

Description 29

Forecast Methodology 30

CROSS-REFERENCE LIST OF TABLES

Provided in Ms. Noe's Exhibits

Table 4—FERC Accounts 451–456 3

Tables 4&5—FERC Accounts 415–416 (excluding 415.002 and 416.002) 5

Table 5—FERC Accounts 500–935 5

Table 6—FERC Accounts 403 and 404 18

Table 6—FERC Accounts 406, 411.6, and 411.7 18

Table 8—FERC Account 407.3 19

Table 7—FERC Account 408.1 20

FERC Accounts 418.1 and 419 21

FERC Accounts 107 22

Table 1—FERC Account 101 23

Table 2—FERC Accounts 108 and 111 25

Table 3—FERC Accounts 154 and 163 26

Table 3—FERC Accounts 182.3 and 186 27

Table 3—FERC Account 105 28

Table 3—FERC Account 252 28

Table 3—FERC Accounts 123.1, 186, and 145 29

INTRODUCTION

This Forecast Methodology Manual ("Manual") was developed solely to provide supporting information for the methodologies that Idaho Power Company used to set the values contained in its proposed 2011 test year in Case No. IPC-E-11-08 before the Idaho Public Utilities Commission ("IPUC"). 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.

These values 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 $1,653,959 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 $1,137,825.

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 $41,565,914 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**

Exhibit No. 20
Case No. IPC-E-11-08
T. Tatum, IPC
Page 11 of 35

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 Plan*—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 (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.** This account is traditionally forecasted using the AURORAxmp® Model. However, for this test year, IPC has included the Base level established in 2010.

- **Account 547—Fuel Expense (Excluding 547.000—Salmon Diesel).** This account is normally forecasted for the test year using the AURORAxmp® Model. However, for the test year, IPC has elected to include, as its 2011 forecast, the previously approved 2010 Base level per IPUC Order No. 31042.

- **Account 555—Purchased Power (Excluding 555.050).** This account is forecasted for the test year using the AURORAxmp® Model. However, for the test year, IPC has elected to include, as its 2011 forecast, the previously approved 2010 Base level per IPUC Order No. 31042 with the exception of adjustments as described in testimony.

- **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.** For the test year, IPC has elected to include, as its 2011 forecast, the previously approved 2010 Base level per IPUC Order No. 31042.

- **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. Fuel expense is normally forecasted for the test year using the AURORAxmp® Model. However, for the test year, IPC has elected to include, as its 2011 forecast, the previously approved 2010 Base level per IPUC Order No. 31042.

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). Fuel and purchased power is normally forecasted for the test year using the AURORAxmp® Model. However, for the test year, IPC has elected to include, as its 2011 forecast, the previously approved 2010 Base level per IPUC Order No. 31042 with the exception of adjustments to Purchased Power as described in testimony.

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 $2,343,493. For the test year, IPC has elected to include, as its 2011 forecast, the previously approved 2010 Base level per IPUC Order No. 31042.

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) 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 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.

Forecast Adjustment J—Allowance for Funds Used During Construction ("AFUDC") Related to Hells Canyon Relicensing

FERC Accounts 107

Description

Account 107 (Constrution Work in Progress) includes the total of the balances of work orders for electric plant in process of construction. Work orders shall be cleared from this account as soon as practicable after completion of the job. Expenditures on research, development, and demonstration projects for construction of utility facilities are to be included in a separate subdivision in this account. Also included in this account is an Allowance for Funds Used During Constuction ("AFUDC"). AFUDC includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission. The rates shall be determined annually.

Forecast Methodology

Forecast Adjustment J is $0, resulting in the AFUDC related to Hells Canyon Relicensing (Account 107) remaining the same as the 2010 Base.

IPC began incurring Hells Canyon relicensing costs in 1999. These relicensing efforts are financed from internally generated funds and from outside sources including short-term debt, long-term debt and new equity. IPC accrues and capitalizes these financing costs to account 107 as AFUDC during the construction phase of the project. AFUDC is calculated monthly using a rate determined by a FERC formula. In the 2008, Idaho General Rate Case Order (IPUC Order No. 30722), IPC requested and was granted the inclusion of the AFUDC related to Hells Canyon Relicensing in the revenue requirement.

As of December 31, 2009 and 2010, Hells Canyon Relicensing, account 107, balances equaled $121,531,533 and $130,209,857, respectively. Of these balances, accumulated AFUDC was $42,165,895 in 2009 and $50,629,008 in 2010.

While AFUDC continues to increase relating to the Hells Canyon Relicensing efforts, IPC is requesting recovery of the same amount ($6,815,472) previously included the 2008 General Rate Case and subsequently approved in IPUC Order No. 30722.

RATE BASE COMPONENTS

Forecast Adjustment K—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).

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 L & M—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 N—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 O—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 P—Plant Held for Future Use

Table 3—FERC Account 105

Description

This account includes the original cost of electric plant owned and held for future use in electric service under a definite plan for such use and includes property acquired but never used by the utility in electric service, but held for such service in the future under a definite plan, and property previously used by the utility in service, but retired from such service and held pending its reuse in the future, under a definite plan, in electric service.

Forecast Methodology

Forecast Adjustment P increases Plant Held for Future Use (Account 105) by $210,000 above the 2010 Base

IPC developed its 2010 Base by removing from the 2010 actual Plant Held for Future Use those properties that it either plans to sell, will be possibly split and partially sold, structures or improvements that will be removed prior to construction and properties for which the use is uncertain.

In addition, IPC included in its forecast adjustment $210,000 for the acquisition of four additional parcels of land that will be acquired by year-end 2011. These include land purchases for the Buhl, Justice and Montour substations and Peterson substation expansion.

Forecast Adjustment Q—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). 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 table below:

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 R—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

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 21

Idaho Power Company
Net Power Supply Expense (NPSE)
PCA Components

	A	B	C	D
Line	PCA Component	2010 Approved*	2011 Test Year	2010 Adjusted
1	Account 501, Coal	$ 167,718,084	$ 146,164,200	$ 167,718,084
2	Account 536, Water for Power	$ 1,828,640	$ 3,314,561	$ 1,828,640
3	Account 547, Gas	$ 6,062,472	$ 5,422,112	$ 6,062,472
4	Account 555, Non-PURPA	$ 66,689,601	$ 63,281,509	$ 66,689,601
5	Account 565, 3rd Party Transmission	$ 8,262,000	$ 7,978,600	$ 8,262,000
6	Account 447, Surplus Sales	$ 92,642,114	$ 61,692,242	$ 92,642,114
7	Net of 95 percent accounts	$ 157,918,683	$ 164,468,740	$ 157,918,683
8				
9	Account 442, Hoku First Block Revenues	$ -	$ 23,921,466	$ 23,921,466
10	Net of 95 percent accounts with Hoku	$ 157,918,683	$ 140,547,274	$ 133,997,217
11				
12	Account 555, PURPA	$ 62,851,454	$ 113,224,604	$ 86,772,920
13	SubTotal NPSE	$ 220,770,137	$ 253,771,878	$ 220,770,137
14				
15	Account 555, Demand Response Incentives		$ 11,252,265	$ 11,252,265
16	Total NPSE	$ 220,770,137	$ 265,024,143	$ 232,022,402

Notes: (*) Base level NPSE approved in Order No. 31042 issued April 13, 2010.