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 IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

PAWEL P. GORALSKI

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Pawel ("Paul") P. Goralski. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as a Regulatory Consultant in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2007, I received a Bachelor of Business Administration degree in Finance from Boise State University in Boise, Idaho. I have also attended "The Basics: Practical Regulatory Training for the Electric Industry," an electric utility ratemaking course offered through the New Mexico State University's Center for Public Utilities, "Electric Utility Fundamentals and Insights," an electric utility course offered by Western Energy Institute, and "Electric Rates Advanced Course," an electric utility ratemaking course offered through the Edison Electric Institute.

Q. Please describe your work experience with Idaho Power.

A. In 2017, I was hired as a Regulatory Analyst in the Company's Regulatory Affairs Department, and in 2020 I was promoted to my current position of Regulatory

Consultant. My primary responsibilities include supporting the Company's class cost-of-service ("CCOS") activities, developing pricing for special contract customers and other large load pricing analysis, supporting the Company's annual Fixed Cost Adjustment ("FCA") calculation, and serving as the Company witness in that matter. I have also been its witness for the Company's annual Demand-Side Management ("DSM") prudency filings.

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

A. My testimony will address derivation of the Company's 2023 CCOS study and the resulting recommendations for customer pricing components. Specifically, my testimony covers the following six areas: 1) CCOS - overview, proposed modifications to methodology, description, and study results, 2) allocation of CCOS-informed revenue requirement to customer classes, 3) computation of the Sales Based Adjustment Rate ("SBAR") consistent with the methodology described in the Settlement Agreement in Case No. IPC-E-15-15,[1] 4) update to FCA components as informed by the 2023 CCOS study and related rate design proposals, 5) Special Contract pricing and rate design, and, 6) Schedule

[1] *In the Matter of Idaho Power Company's Application for Approval of Computational Modifications to the True-Up Portion of the Power Cost Adjustment*, Case No. IPC-E-15-15 (filed April 28, 2015; Final Order No. 33307 issued May 28, 2015).

20 – High-Density Load ("Schedule 20") pricing and update on Schedule 20 customers and interruption compensation.

I. <u>CLASS COST-OF-SERVICE OVERVIEW</u>

Q. Please describe in general terms the process used to prepare the class cost-of-service study.

A. There are two general steps used in preparing a class cost-of-service study. The first step is to determine the total costs of providing electric service, adjusted for normal weather and water conditions. These costs have been provided to me by Company Witness Ms. Kelley Noe on Exhibit No. 35. The next step is to establish a methodology for the separation of those costs among customer classes.

Q. What methodology is used to separate costs among customer classes?

A. The methodology for separating costs among classes consists of a three-step process generally referred to as functionalization, classification, and allocation. In all three steps, recognition is given to the way in which the costs are incurred by relating these costs to the way in which the utility is operated to provide electrical service.

Q. Please explain the meaning of functionalization.

A. Costs must be functionalized; that is, identified with utility operating functions. Operating functions recognize the different roles played by the various facilities in the electric utility system. In the Company's accounts, these various roles are already recognized to some degree, particularly in the recording of plant costs as production-, transmission-, or distribution-related. However, this functional breakdown is not sufficiently detailed for cost-of-service purposes. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions, such as substations, primary lines, secondary lines, and meters. This level of functionalization allows costs to be more equitably allocated among classes of customers.

Q. Please explain the meaning of classification.

A. In addition to functionalization, classification refers to the identification of a cost as being either customer-related, demand-related, or energy-related. These three cost components are used to reflect the fact that an electric utility makes service available to customers on a continuous basis, provides as much service, or capacity, as the customer desires at any point in time, and supplies energy, which provides the customer the ability to do useful work over an extended period of time. These three concepts of availability, capacity, and energy are related to the three components of cost designated as customer, demand, and energy, respectively. In order to classify a particular cost by component, primary attention is given to whether the cost varies as a result of changes in the number of customers, changes in demand imposed by the customers, or changes in energy used by the customers.

Q. What are some examples of customer-, demand- and energy-related costs?

A. Examples of customer-related costs are the plant investments and expenses that are associated with meters and service drops, meter reading, billing and collection, and customer information and services, as well as a portion of the investment in the distribution system. These investments and expenses are made and incurred based on the number of customers, regardless of the amount of energy used, and are, therefore, generally considered to be fixed costs. Demand-related costs are the fixed costs associated with investments in generation, transmission, and a portion of the distribution plant and the associated operation and maintenance expenses necessary to accommodate the maximum demand imposed on the Company’s system. Energy-related costs are generally the variable costs associated with the operation of the generating plants, such as fuel.

Q. What did you use as your primary guide in classifying costs as either customer-, demand-, or energy-related?

A. I used the *Electric Utility Cost Allocation Manual*, published January 1992, by the National Association of Regulatory Utility Commissioners as my primary guide to the classification of customer-, demand-, and energy-related costs.

Q. Please explain the process of allocation.

A. The process of allocation is one of apportioning the total jurisdictional cost among classes by introducing allocation factors into the process. An allocation factor is nothing more than an array of numbers that specifies the class value or share of a total jurisdictional quantity.

Once individual costs have been allocated to the various classes of service, it is possible to total these costs as allocated and arrive at a breakdown of utility rate base and expenses by class. The results are stated in a summary form to measure adequacy of revenues for each class. The measure of adequacy is typically the rate of return earned on rate base compared to the requested rate of return.

Q. Have you provided separate documentation describing in detail the methodology used to prepare the Company's class cost-of-service study?

A. Yes. Exhibit No. 36, the Class Cost-of-Service Process Guide, describes in detail the methodology used in the preparation of the Company's class cost-of-service study.

II. PROPOSED MODIFICATIONS TO THE COMPANY'S COST-OF-SERVICE METHODOLOGY

Q. Is the Company proposing modifications to the CCOS study methodology most recently approved by the Idaho Public Utilities Commission ("Commission") in the 2008 general rate case ("GRC") and that was also utilized in the 2011 GRC?

A. Yes. I am proposing two modifications to the CCOS methodology most recently approved by the Commission. However, much of the study's methodology remains consistent with the 2008 and 2011 GRC CCOS studies.[2]

Q. Please describe the primary elements that remain consistent between the 2023 CCOS and the study prepared for the 2011 GRC.

[2] *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, Larkin DI (filed June 1, 2011).

In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service, Case No. IPC-E-08-10, Tatum DI (filed June 27, 2008).

A. Generally, the 2023 CCOS remains consistent with the 2011 CCOS study, including, but not limited to:

- Demand-classified base-load serving generation plant is allocated based on a monthly system coincidence peak ("12CP") allocator;
- The Company's hydro and coal-fueled generation plants are functionalized as base-load serving generation resources, while the Danskin and Bennett Mountain natural gas-fueled generation plants are functionalized as peak-load serving generation resources;
- Transmission plant is 100 percent demand-classified and allocated based on a 12CP, marginal-cost weighted allocator;
- Energy-related cost allocators continue to be derived based on an averaging approach inclusive of marginal-cost weighting;
- The Company's 12CP values, and each class's share of that value, is adjusted to add back the impact of Demand Response, that is, system load is representative of load as if no Demand Response events had been called; and
- Classification of distribution plant between demand and customer is based on a three-year load duration curve.

Q. Please describe the first modification made to CCOS methodology.

A. As described by Company Witness Ms. Aschenbrenner, analysis completed in support of the Company's upcoming 2023 Integrated Resource Plan indicates there is a probability that high-risk hours occur into the month of September. As a result, I recommend allocation of peak-load serving resources be based on a summer period June through September 4CP allocator, updated from the June through August 3CP allocator utilized in the 2011 CCOS. The four-month summer season better aligns with current and future high-risk hours and the need to rely on peak-load serving resources to meet those high-risk hours.

Q. Did the CCOS modification to extend the summer season to include September impact all customer classes?

A. No. Idaho Power's Irrigation class service schedule, Schedule 24, has previously utilized a different seasonal definition than other rate schedules. While all other Idaho Power rate schedules with seasonal rates have previously defined the summer season as June through August, the Irrigation customer class has historically received a portion of cost allocation and rates based on a summer period definition including September. The proposed CCOS modification for summer-season baseload serving generation resources to be allocated on a June through September period aligns cost allocation for the summer season for all customer classes.

Q. Please describe the second recommended CCOS modification.

A. In past studies, classification of Idaho Power's cost of generation - with respect to base-load serving generation plant rate base, expenses, and power supply expenses - has included both energy and demand classification based on a jurisdictional load factor. That is, if the Idaho jurisdictional load factor was 55 percent, 55 percent of baseload generation plant was classified as energy, with amounts exceeding the jurisdictional load factor classified as demand-related.

Idaho Power proposes to change classification methodology such that energy and demand classification follow a more "accounting-like" fixed cost versus variable cost approach. All base-load serving generation fixed accounting costs would be 100 percent demand classified, and all variable expenses, such as fuel and purchased power expenses, would be 100 percent energy classified.

Q. How does this impact the classification of generation and power supply by FERC account?

A. Please see Table 1 for a comparison of main FERC account classification under the recommended methodology and the Company's previous methodology. Peak-load generation plant continues to be 100 percent demand-classified and fuel expense continues to be 100 percent energy classified. For base-load serving generation plant: hydro, steam, and natural-gas fueled, 100 percent of generation plant is demand-classified. Power supply expense, including account 555.0 purchased power, and 555.1 – PURPA are 100 percent energy classified. It should be noted that while Table 1 is not a comprehensive list of impacted FERC accounts (there are also impacts to composite allocators that include the FERC accounts below), the list identifies the primary accounts that drive changes in cost assignment.

Table 1
Primary Production & Power Supply Expense FERC Account Classification Comparison

FERC Account	Description	Prior Classification	Recommended Classification
501	Steam Plant - Fuel	100% Energy	100% Energy
536	**Water lease & Other**	**Demand/Energy**	**100% Energy**
547	Other Generation - Diesel	100% Energy	100% Energy
547	Other Generation - Other Fuel	100% Energy	100% Energy
555.1	**Purchased Power**	**Demand/Energy**	**100% Energy**
555.1	Purchased Power - Demand Response Incentives	100% Demand	100% Demand
555.2	**Purchased Power - PURPA**	**Demand/Energy**	**100% Energy**
310-316	**Steam Production**	**Demand/Energy**	**100% Demand**
330-336	**Hydraulic Production**	**Demand/Energy**	**100% Demand**
340-346	**Other Production - Langley**	**Demand/Energy**	**100% Demand**

Q. Why is the Company proposing this change in classifying costs?

A. Idaho Power has used, and the Commission has approved, the use of a jurisdictional load factor to classify base-load generation expense since the early 1980s. As explained by Ms. Aschenbrenner, the Company seeks to modernize rate design to better align cost-causation with fixed and variable components of Idaho Power's cost structures. Because the results of classification are used to inform rate design, I am proposing a method to align with the Company's rate design objectives.

Q. What additional changes are incorporated in the 2023 CCOS study?

A. There are several cost categories that are new to the CCOS study since the Company's 2011 GRC. The more recent cost categories are described in detail in Mr. Larkin's testimony, and are allocated in the CCOS study in the following manner:

- Other Production – Langley: base-load serving generation; 100 percent demand-classified;
- 120 megawatt ("MW") battery storage: base-load generation; 100 percent demand-classified;
- Jackpot Power Purchase Agreement ("PPA"):[3] 100 percent energy classified;

[3] The Jackpot PPA is described in the Direct Testimony of Company Witness Ms. Jessica Brady.

- Energy Imbalance Market expenses: follows transmission plant allocation as the ability for Idaho Power to access the market is determined by transmission capacity;
- Western Resource Adequacy Program: also follows transmission plant allocation for FERC account 561 – Transmission – Load Dispatching;
- Wildfire mitigation: wildfire mitigation supports the Company's overall electrical system and is allocated based on a composite allocator for generation, transmission, and distribution plant.

Q. Are there any other major changes to the 2023 CCOS study from the CCOS filed in the 2011 GRC?

A. Yes, the 2023 CCOS study separately allocates costs to the on-site generation class for Residential, Schedule 6, and Small-General service, Schedule 8, as independent rate classes for cost assignment. The Commission approved the creation of Schedule 6 and 8 in 2018.[4] These load statistics were developed by the Company's Load Research and Forecasting Department and are described in workpapers filed by Mr. Larkin.

[4] *In the Matter of the Application of Idaho Power Company for Authority to Establish New Schedules for Residential and Small General Service Customers with On-Site Generation*, Case No. IPC-E-17-13, Order No. 34046 (May 9, 2018).

Q. How are the clean energy aspects of Micron's Special Contract accounted for in the CCOS?

A. As described in Mr. Larkin's testimony, because costs and revenues from Micron's payment for the Black Mesa PPA are offsetting, they are excluded from the Idaho jurisdictional revenue requirement, and are also excluded from CCOS. While costs and revenues were excluded from CCOS, derivation of the energy-allocator for Micron was adjusted to exclude energy met by the Black Mesa resource. That is, the energy service Micron requires from Idaho Power is reduced by the forecast generation of the Black Mesa PPA, consistent with the Special Contract billing construct. This modification ensures Micron receives its fair, allocable share of power supply expense for the portion of load met by Idaho Power.

III. COST-OF-SERVICE STUDY DESCRIPTION

Q. Have you prepared a table that summarizes the basis by which each of the major functionalized cost categories has been classified and subsequently allocated to customer classes under the CCOS?

A. Yes. The Table 2 summarizes the basis by which each of the major functionalized cost categories is classified and subsequently allocated to customer classes under the CCOS:

Table 2
CCOS Classification and Functionalization Summary

Cost Category	Classification Basis
Generation Plant	
Hydro and Steam Production	Demand
Other Production (Langley & Peaking Units)	Demand
Transmission Plant	Demand
Distribution Plant	Demand and Customer
Other Expenses	
Fuel	Energy
Purchased Power	Energy
Demand Response Incentive Payments	Demand
Cost Category	**Allocation Basis**
Generation Demand	
Hydro and Steam Production	12CP without Marginal Generation Cost Weighting
Other Production (Langley)	12CP without Marginal Generation Cost Weighting
Other Production (Peaking Units)	4CP without Marginal Generation Cost Weighting
Demand Response Incentive Payments	4CP without Marginal Generation Cost Weighting
Generation Energy	12 Months Energy with Marginal Energy Cost Weighting (averaged w/ un-weighted values)
Transmission	12CP with Marginal Transmission Cost Weighting
Distribution	1NCP / No. of Customers / Direct Assignment

Q. Please identify the exhibits that comprise the cost-of-service study.

A. The cost-of-service study is comprised of the following exhibits:

1. Exhibit No. 37, Functionalization and Classification of Costs;
2. Exhibit No. 38, Summary of Functionalized Costs;
3. Exhibit No. 39, Allocation to Classes;
4. Exhibit No. 40, Summary of Class Allocations;
5. Exhibit No. 41, Transfer Adjustment;
6. Exhibit No. 42, Revenue Requirement Summary;
7. Exhibit No. 43, Class Cost-of-Service Unit Costs;
8. Exhibit No. 44, Marginal Cost Study
9. Exhibit No. 45, Development of Weighted Demand and Energy Allocators;
10. Exhibit No. 46, Revenue Requirement Adjustments.

Q. Please describe Exhibit No. 37.

A. Exhibit No. 37 contains 145 pages and consists of 11 Cost Functionalization and Classification Tables. The functionalization and classification of each component of rate base, operating revenue, and expense are treated in detail in these tables. The tables are shown in the following sequence:

- Table 1 - Electric Plant in Service;

- Table 2 - Accumulated Provision for Depreciation;
- Table 3 - Additions and Deletions to Rate Base;
- Table 4 - Operating Revenues;
- Table 5 - Operation and Maintenance Expenses;
- Table 6 - Depreciation and Amortization Expense;
- Table 7 - Taxes Other Than Income Taxes;
- Table 8 - Regulatory Debits/Credits;
- Table 9 - Income Taxes;
- Table 10 - Development of Labor-Related Allocator; and
- Table 11 - Functionalization Allocators.

Q. What is the significance of the column header "Allocator" on Exhibit No. 37?

A. This column identifies, by symbol, the basis for each allocation. For example, for Accounts 310 through 316, Steam Production, shown at line 20 on page 1, the constant "PI-S" is used to allocate the total investment in steam production plant to the production function and to the demand cost classifications. The resultant functionalization of costs may itself serve as a basis for subsequent allocations. This use is illustrated at line 119 on page 21 where the accumulated depreciation for steam production plant is allocated according to the same allocator “PI-S” used at line 20.

Q. Please describe Exhibit No. 38.

A. Exhibit No. 38 summarizes in row format the functionalized costs for each component of rate base and expenses shown across the columns on Exhibit No. 37.

Q. Please describe Exhibit No. 39.

A. Exhibit No. 39 details the allocation of the summarized costs shown on Exhibit No. 38 to each customer class, including the Special Contract customers. The exhibit also includes a summary of results showing the actual rate of return earned for each customer class and Special Contract customer. The exhibit includes the following tables:

- Table 1 - Plant in Service;
- Table 2 - Accumulated Reserve for Depreciation;
- Table 3 - Amortization Reserve;
- Table 4 – Substation Contributions in Aid of Construction;
- Table 5 - Customer Advances for Construction;
- Table 6 - Accumulated Deferred Income Taxes;
- Table 7 - Acquisition Adjustment;
- Table 8 - Working Capital;

- Table 9 - Deferred Programs;
- Table 10 - Subsidiary Rate Base;
- Table 11 - Plant Held for Future Use;
- Table 12 - Other Revenues;
- Table 13 - Operation & Maintenance Expenses;
- Table 14 - Depreciation Expense;
- Table 15 - Amortization of Limited Term Plant;
- Table 16 - Taxes Other Than Income;
- Table 17 - Regulatory Debits/Credits;
- Table 18 - Provisions for Deferred Income Taxes;
- Table 19 - Investment Tax Credit Adjustment;
- Table 20 - Construction Work In Progress;
- Table 21 - State Income Taxes;
- Table 22 - Federal Income Taxes; and
- Table 23 - Allocation Factor Summary.

Q. Does the Class Cost-of-Service Process Guide, Exhibit No. 36, detail the manner in which you allocated the summarized costs shown on Exhibit No. 38 to each class of service as shown on Tables 1 through 22 of Exhibit No. 39?

A. Yes. Exhibit No. 36, the Class Cost-of-Service Process Guide, details the majority of the allocation methodology that was applied to produce the results shown on Tables 1 through 22 of Exhibit No. 39.

Q. What additional allocation methodology was included in the CCOS to produce the summarized costs shown on Exhibit No. 42?

A. As described by Mr. Larkin, the Jurisdictional Separation Study includes three additional revenue requirement line items: 1) Bridger revenue requirement, 2) Valmy revenue requirement, and 3) revenue requirement offset for battery projects to be installed in 2023. Revenue requirements for those three items were allocated to customer classes consistent with other base-load serving generation plant. Please see Exhibit No. 46 Revenue Requirement Adjustments for each class's calculated allocable share. The result of that class allocation for the three revenue requirement items is listed by customer class on row 45 of Exhibit No. 42 Revenue Requirement Summary.

A second allocation was included to spread to customer classes the transfer adjustment described by Mr. Larkin. The total value of the Energy Efficiency Rider labor adjustment and update to Power Cost Adjustment ("PCA")-related items were allocated to customer classes in the same manner as they would be incurred. Exhibit No. 41, Transfer Adjustment, computes the base revenue transfer for each customer class.

Q. Does Exhibit No. 39 include a listing of the allocation factors used to allocate to classes the various costs shown on Tables 1 through 22?

A. Yes. Table 23 of Exhibit No. 39 includes a listing of each allocation factor.

Q. Have you included information regarding the derivation of the Company's updated marginal costs with your testimony?

A. Yes. I have included a copy of the Company's 2023 Marginal Cost Analysis Study as Exhibit No. 44.

Q. Have the marginal costs been used to develop the Company's revenue requirement?

A. No. The marginal costs have been used solely for purposes of developing allocation factors and not for purposes of developing the Company's revenue requirement.

Q. Have you prepared an exhibit that details the derivation of the demand and energy allocation factors used in the cost-of-service study?

A. Yes. Exhibit No. 45 details the derivation of the allocation factors D10S, D10NS, D10P, D13, E10S, and E10NS used in the CCOS.

IV. COST-OF-SERVICE STUDY RESULTS

Q. Please describe Exhibit No. 42.

A. Exhibit No. 42 is the revenue requirement summary based on the results of the proposed CCOS study. The section headed "Revenue Requirement for Rate Design" details the sales revenue required from each customer class and special contract customer. The sales revenue required includes return on rate base, total operating expenses, and incremental taxes computed using the net-to-gross multiplier of 1.347 provided by Ms. Noe.

Q. Have you prepared an exhibit quantifying the impact from the recommended CCOS modifications?

A. Yes, Exhibit No. 47 to my testimony includes the results of the 2023 CCOS study and the three supplemental CCOS studies. The exhibit is presented with the first section representing a CCOS study consistent with the 2011 GRC methodology; the two subsequent sections independently list the incremental change to revenue requirement by class from that respective modification. Finally, the combined impact of the modifications and the 2023 CCOS class revenue requirement results are listed in the fourth section.

Q. Please summarize the major impacts to customer classes from the recommendations.

A. The greatest impact is to the Irrigation customer class, which is primarily driven by shifting to a four-month summer season for all customer classes, and results in a reduction in revenue deficiency of $3.7 million (as compared to the 2011 GRC methodology) from this modification. However, while each class experiences a slight change to revenue requirement from the two proposed changes, the greatest percentage total impact is a 2.65 percent reduction in revenue deficiency for the Irrigation class, nearly all due to the four-month summer season, with almost all other classes experiencing less than 1 percent impact to revenue requirement from the proposed methodology changes.

Q. Please summarize the results of the class cost-of-service study that are detailed on Exhibit No. 42.

A. The results shown on Exhibit No. 42 indicate that the Residential ("Schedule 1"), Residential On-Site Generation ("Schedule 6"), Small General Service ("Schedule 7"), Small General Service On-Site Generation ("Schedule 8") Irrigation Service ("Schedule 24"), and Traffic Control Lighting Service ("Schedule 42") should have an increase in rates that is greater than the overall average increase requested by the Company. In addition, the results indicate that Large General Service – Primary & Transmission ("Schedules 9P and 9T"), Dusk to Dawn Lighting ("Schedule

15”), Municipal Street Lighting (“Schedule 41”), and Special Contract customer J. R. Simplot Company Pocatello, Idaho (“Simplot Pocatello”) (“Schedule 29”) should have a decrease in rates from the current level.

V. REVENUE REQUIREMENT ALLOCATION

Q. What is the Company’s general ratemaking philosophy on determining class-specific revenue requirement and the resulting customer rates?

A. The Company’s primary approach to ratemaking in the last several GRCs has been to establish rates that reflect costs as accurately as possible. Accordingly, the Company’s ratemaking proposals usually advocate movement toward cost-of-service results, which assign costs to those customer classes that cause the Company to incur the costs.

Q. Are there other objectives that may be considered in the ratemaking process?

A. Yes. The Commission may consider a number of other objectives, such as rate stability, in the determination of rates.

Q. How did you approach the determination of the revenue requirement for each customer class?

A. As I described above, a pure cost-of-service revenue requirement spread would result in larger increases for certain classes relative to the overall average increase. In order to mitigate the magnitude of the maximum rate increase any class would experience, the Company is proposing to cap the percentage increase to any customer class at one and one-half times the overall average requested increase, or 12.91 percent (8.61 percent X 1.5 = 12.91 percent). As proposed, Large General Service – Primary & Secondary, Dusk to Dawn Lighting, Municipal Street Lighting and the Simplot Pocatello Special Contract receive neither a decrease nor an increase in rates.

Q. Did you discuss the results of the CCOS study internally before deciding to apply the 12.91 percent caps to the specified customer classes?

A. Yes. I discussed the results of the CCOS and potential rate spread scenarios with Company Witness Mr. Timothy Tatum, who is responsible for the overall preparation of this case. My revenue allocation is the result of those discussions.

Q. Was the revenue allocation process affected by the clean energy aspects of Micron's Special Contract?

A. No. Micron's revenue targets were developed for the portion of service Idaho Power provides.

Q. Does the overall 12.91 percent cap also apply to new customer classes Schedule 6 and 8?

A. Not explicitly. However, consistent with the direction provided by Ms. Aschenbrenner, the Residential and Residential On-Site Generation customer classes were combined prior to determining the revenue target. The same occurred for Small General Service and its On-Site Generation counterpart. As further discussed in the Direct Testimony of Company Witness Mr. Grant Anderson and Company Witness Mr. Zack Thompson, respectively, rate design was developed such that Schedule 1 and Schedule 6 share the same service charge and energy rates, with that also being the case for Schedule 7 and Schedule 8.

Q. Do you have an exhibit that details the class revenue requirement determination?

A. Yes. Exhibit No. 48 is a five-page exhibit that steps through the revenue requirement allocation process from the CCOS results to the ultimate proposal for each customer class. Page 1 of Exhibit No. 48 presents the proformed normalized test year sales and revenues and transfer adjustment by customer class. Page 2 details the results from the CCOS study and illustrates the revenue changes that would be made to each customer class to obtain the CCOS results. Page 3 shows the revenue shortfall that resulted by applying the 12.91 percent cap to combined Small General Service classes, Irrigation, and Traffic Control Lighting, and no decrease to Large General Service – Primary & Secondary, Dusk to Dawn Lighting, Municipal Street Lighting, or Simplot Pocatello Special Contract.

Page 5 shows the final proposed increase to customer classes that resulted from spreading the revenue shortfall created by the 12.91 percent cap, no increase or decrease to Large General Service – Primary & Secondary, Dusk to Dawn Lighting, Municipal Street Lighting, or Simplot Pocatello Special Contract. The results from page 5 were utilized in determining the individual rates for the Company's general tariff and special contract customers.

Q. Did you also provide the results of the CCOS to the Company's rate design witnesses for use in the Company's rate design proposals along with the revenue targets from Exhibit No. 48?

A. Yes. I provided the CCOS unit costs, detailed on Exhibit No. 43, to Mr. Anderson, Mr. Thompson, and Company Witness Mr. Riley Maloney for use in determining the rates for their respective service schedules.

Q. Please describe Exhibit No. 43.

A. Exhibit No. 43 shows the unit cost for each function for metered service schedules as determined through the CCOS study. The billing units shown in the column labeled "(F)" reflect the billing demands, normalized billing energy, basic load capacity, and number of billings.

Q. Are you proposing any other changes to cost recovery?

A. Yes, As discussed by Mr. Tatum, the Company is proposing to reduce the Energy Efficiency Rider ("Rider") collection percentage to 2.25 percent from 3.10 percent. Exhibit No. 41 includes derivation of the proposed 2.25 percent Rider collection percentage, with Rider collection projected to be $31.6 million, just slightly above the current funding level when also considering the $3.5 million of labor-related cost that will be collected in base rates.

VI. SALES BASED ADJUSTMENT RATE

Q. Please describe in general terms the purpose of the SBAR?

A. The SBAR is a part of the PCA mechanism that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns.

Q. Please describe the SBAR methodology approved by the Commission in Order No. 33307.

A. Commission Order No. 33307 directs the Company to calculate the SBAR based on the energy classified portion of embedded production revenue requirement as established in the CCOS. The final SBAR is calculated by dividing this portion of revenue requirement by the Idaho kilowatt-hour ("kWh") sales for the test year.

Q. Are any additional modifications to calculate the SBAR necessary as part of the 2023 CCOS determination?

A. Yes. The Commission's Order adopted Commission Staff's ("Staff") recommendations for the PCA treatment of the renewable portion of Micron's billing construct,[5] which accepted the proposed treatment described in Ms. Aschenbrenner's testimony filed in Case No. IPC-E-22-06:[6]

> Further, any energy requirements met by the Renewable Resource will not be included in the PCA sales based adjustment (SBA) and will not be used in the derivation of the future PCA rates. All Supplemental Energy supplied to Micron will be included in the PCA, SBA and used for PCA rate derivation purposes.

Accordingly, the Black Mesa PPA power supply expense is excluded as part of the SBAR energy-related generation function revenue requirement, and the portion of Micron's energy that Black Mesa meets under the Special Contract billing construct is also excluded from test year retail sales.

Q. What is the resulting SBAR?

A. By applying the methodology established by

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[5] *In the Matter of Idaho Power Company's Application for Approval of a Replacement Special Contract with Micron Technology, Inc. and a Power Purchase Agreement with Black Mesa Energy, LLC.*, Case No. IPC-E-22-06, Order No. 35482 (August 1, 2022); Staff Comments pg. 18.
[6] Case No. IPC-E-22-06, Aschenbrenner DI, pg. 20.

Commission Order No. 33307 in Case No. IPC-E-15-15, and for the Micron clean energy component of their Special Contract components by Order No. 35482, the SBAR should be increased from the requested level of $26.72 in Case No. IPC-E-15-15 to $31.29 per megawatt-hour.

Q. Have you prepared an exhibit that details the derivation of the revised SBAR?

A. Yes. Exhibit No. 49, details the derivation of the $31.29 SBAR amount.

VII. FIXED COST ADJUSTMENT RATES

Q. Please describe the FCA mechanism.

A. The FCA is a rate mechanism that is designed to remove the financial disincentive to utility acquisition of demand-side management resources. The mechanism accomplishes this goal by severing the link between energy sales and the recovery of fixed costs. The FCA applies to customer classes that only include energy and service charges in their retail billing components, Residential Service (Schedules 1, 3, 5, and 6) and Small General Service (Schedule 7, and 8). The annual FCA amount is determined according to the following formula:

FCA = (CUST X FCC) – (ACTUAL X FCE)

Where:

FCA = Fixed Cost Adjustment;

CUST = Actual number of customers, by class;

FCC = Fixed Cost per Customer, by class;

ACTUAL = Actual Billed kWh Energy Sales, by class; and

FCE = Fixed Cost per Energy, by class.

Q. What values are required to calculate the FCA amount annually?

A. As outlined in the above formula, for each class (Residential Service and Small General Service), the actual number of customers ("CUST"), the fixed cost per customer ("FCC"), actual energy ("ACTUAL"), and the Fixed Cost per Energy ("FCE") are required to determine the FCA amount. Two of these variables (CUST and ACTUAL) are determined at the end of each year based upon the Company's actual billing records. The other two variables (FCC and FCE) are updated each time the Company files a GRC and are based on the results of the CCOS study.

Q. Since granting permanency for the FCA mechanism in Order No. 32505 in 2012,[7] has the Commission authorized any additional changes?

A. Yes. First, the Commission approved a Settlement Stipulation in 2015 that replaced the use of weather-normalized data with actual sales in determination

[7] *In the Matter of the Application of Idaho Power Company for Authority to Convert Schedule 54 – Fixed Cost Adjustment – from a Pilot Schedule to an Ongoing Schedule*, Case No. IPC-E-11-19, Order No. 32505 (March 30, 2012).

of the FCA deferral.[8] Second, in 2021 the Commission approved separate, and reduced fixed cost tracking for customers considered "new," defined in the Order to be customers added after January 1, 2022.[9] The Commission's rationale stated that the modification "eliminates fixed cost recovery due to new customer growth for investments best determined in a general rate case."[10]

Q. Beginning with the 2024 FCA deferral, who will be considered a "new" customer?

A. The FCC and FCE rates will be reset based on outcomes of this GRC, as such, "new" customers will also be reset to be those customers added starting January 1, 2024, when proposed GRC rates go into effect.

Q. Are you proposing any additional modifications to the FCA as part of this proceeding?

A. Yes, I am proposing two additional modifications. First, because Schedule 6 and Schedule 8 are now separate rate classes in the CCOS study with individual cost assignment and independent class statistics, I recommend separate determination of use per customer ("UPC"), FCC, and FCE for these customer classes.

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[8] *In the Matter of the Commission's Inquiry into Idaho Power Company's Fixed Cost Adjustment Mechanism*, Case No. IPC-E-14-17, Order No. 33295 (May 6, 2015).

[9] *Idaho Power Company's Application for Modification of the Fixed Power Cost Adjustment*, Case No. IPC-E-21-39, Order No. 35273 (Dec. 28, 2021).

[10] Order No. 35273, pg. 4.

Next, I am proposing separate determination for the UPC and FCE applied to customers taking service under the Proposed Schedule 5, Residential Service Time-of-Use Plan ("Schedule 5"). Cost assignment for Residential customers is completed on a composite group including Schedule 1, 3, and 5 customers and the FCC is calculated based on class statistics from this composite group. However, UPC for Schedule 5 is approximately 50 percent higher than the average Residential Service (Schedule 1) standard service customer. To appropriately track actual sales against a UPC basis, a class-specific UPC basis should be utilized.

For the FCE, derivation independent from composite Residential FCE rates should be utilized because of the proposed Schedule 5 rate design. As detailed in Mr. Anderson's testimony, the Company is pursuing an update to Schedule 5 time-of-use rates such that on- and off-peak energy rates maintain a four-to-one price differential in the summer season, and 1.5-to-one price differential in the non-summer season. That is, the summer on-peak energy rate will be four times the summer off-peak energy rate, and the non-summer on-peak energy rate will be 1.5 times the non-summer off-peak energy rate. Neither differential aligns with CCOS-informed rates, thus the FCE for Schedule 5 incorporates a matching four-to-one differential for summer, and 1.5-to-one differential for non-summer consumption, such that changes to Schedule 5 energy consumption in response to price signals between on- and off-peak periods recognize the embedded level of fixed costs in each time period. Schedule 5 customers who shift use from the on-peak period to the off-peak period do not receive an under- or over-collection of fixed costs between energy rates and the FCA mechanism because the FCE includes a four-to-one, and 1.5-to-one differential, respectively.

Q. Is the Company proposing changes to how annual FCA rates that recover the FCA deferral are set and applied to customer classes?

A. No. Annually, the FCA deferral will be tracked for five customer segments: Schedule 1 & 3, Schedule 5, Schedule 6, Schedule 7, and Schedule 8. The determination of annual FCA rates combines the Residential and Small General Service customer segments first, and sets the percentage change on an overall basis, not on a class-segment basis. FCA rates will continue to be set only at the total Residential (Schedule 1, 3, 5, and 6) segment, and Small General Service (Schedule 7, and 8) segment.

Q. Have you updated the FCC and FCE rates as part of this GRC proceeding?

A. Yes. I have updated the new and existing customer FCC and the FCE rates using the functionalized and classified revenue requirement from the 2023 CCOS, and proposed Service Charge collection effective January 1, 2024. The updated FCC and FCE rates have been included in the revised Schedule 54, Fixed Cost Adjustment.

Q. Please describe the process used to determine the FCC and FCE rates for the FCA mechanism, which have been submitted as part of this GRC proceeding.

A. The FCC and FCE rates submitted as part of this GRC proceeding are based upon the 2023 test year. These rates most accurately represent the Company's current fixed costs. Exhibit No. 50, Tables I, II, III, IV, and the Schedule 5 FCE derivation detail the computational process that was used to determine these class-specific fixed-cost amounts.

The first step in this process is a determination of the 2023 test year fixed cost recovery embedded in the energy charges for Residential Service and Small General Service customers. As can be seen on Exhibit No. 50, Table III, column J, for Residential Service, $367,032,962 of fixed costs are to be recovered from residential customers through energy charges, and $8,715,991 for Residential On-Site Generation customers. For Small General Service, $8,266,319 of fixed costs are to be recovered from the energy charges, and $27,218 for Small General Service On-Site Generation customers.

Q. Do these fixed cost amounts for the

Residential class include more than their actual class cost of service?

A. Yes. There is a difference between the class cost of service numbers and the amount of requested revenue requirement. This difference is a result of the cross-class subsidies that are currently present in the Company's rate structure. The total cross-class subsidies, as well as the fixed cost portion of those subsidies, are identified on Exhibit No. 50, Table II.

Q. Why is it important to include these fixed cost subsidies for the Residential class?

A. When fixed costs are recovered through a volumetric rate, the effects of any energy efficiency program that reduces energy consumption result in lost recovery of those fixed costs. In the case of the Residential classes, the reduction of energy consumption through energy efficiency not only prevents the Company from recovering the fixed costs associated with those classes, but in addition, prevents the fixed cost recovery of the other inter-class subsidies that are embedded in Residential energy rates.

Q. How are the class-specific fixed cost amounts established in the initial step used to derive the updated FCC rates?

A. The determination of the FCC rate utilizes the annual average number of customers for the Residential customer class and Small General Service customer class. As can be seen on Exhibit No. 50, Table III, column A, the 2023 average number of customers are 492,481 for the Residential customer class, 13,288 for the Residential On-Site Generation class, 30,401 for the Small General Service customer class, and 88 for the Small General Service On-Site Generation class.

With these two principal base level values, the FCC rate can be determined. The annual fixed costs recovered through the energy charges divided by the 2023 average number of customers results in an annual fixed cost recovery per customer, or the FCC rate, shown on Exhibit No. 50, Table III, column K. For the Residential class, the annual fixed cost recovery per customer is $745.27 ($367,032,692 / 492,481), and $655.94 for the Residential On-Site Generation class ($8,715,991 / 13,288). For the Small General Service class, the annual fixed cost recovery per customer is $271.91 ($8,266,319 / 30,401), and $311.07 for the Small General Service On-Site Generation class ($27,218 / 88).

For new customers, those added starting January 1, 2024, the Fixed Cost per Customer – Distribution ("FCC-DIST") only includes distribution function fixed costs. The table below lists the corresponding FCC-DIST for each of the FCA classes.

Table 3
New Customer FCC-DIST

Customer Group	Total Distribution & Customer Fixed Cost Revenue from Energy Charges	2023 Avg. Customers	FCC-DIST
Residential	125,476,059	492,481	$254.78
Residential On-Site Generation	3,620,717	13,288	$272.49
Small General Service	3,257,318	30,401	$107.15
Small General Service On-Site Generation	12,337	88	$140.99

Q. How are the class-specific fixed cost amounts established in the initial step used to derive the updated FCE values?

A. The determination of the FCE rate utilizes the Residential and Small General Service weather-normalized energy consumption for the 2023 test year. As can be seen on Exhibit No. 50, Table III, column B, the 2023 weather-normalized annual energy consumption for the Residential customer class is 5,425,559,433 kWh, 122,912,496 kWh for Residential On-Site Generation customers, 138,285,160 kWh for the Small General Service class, and 370,708 kWh for the Small General Service On-Site Generation class.

The annual fixed cost recovered through the energy charges divided by the normalized energy results in an annual fixed cost recovery per kWh, or the FCE rate, shown on Exhibit No. 50, Table III, column L. Matching FCC-DIST determination for new customers, the FCE-DIST determination for new customers added starting January 1, 2024, only includes distribution-related fixed costs. Existing customer FCE and new customer FCE-DIST are listed in Table No. 4 for each of the FCA classes. Derivation of FCE-DIST is shown on Exhibit No. 50, Table IV.

Table 4
FCE and FCE-DIST

Customer Group	Total Fixed Cost Revenue from Energy Charges	2023 kWh	FCE
Residential (Schedule 1, and 3)	367,032,962	5,425,559,433	$0.067649
Residential On-Site Generation	8,715,991	122,912,496	$0.070912
Small General Service	8,266,319	138,285,160	$0.059777
Small General Service On-Site Generation	27,218	370,708	$0.073423
Customer Group	**Total Distribution & Customer Fixed Cost Revenue from Energy Charges**	**2023 kWh**	**FCE-DIST**
Residential (Schedule 1, and 3)	125,476,059	5,425,559,433	$0.023127
Residential On-Site Generation	3,620,717	122,912,496	$0.029458
Small General Service	3,257,318	138,285,160	$0.023555
Small General Service On-Site Generation	12,337	370,708	$0.033278

Q. Please describe Schedule 5 FCE and FCE-DIST derivation.

A. The kWh sales forecast for Schedule 5 customers is multiplied by the Residential FCE to determine the actual fixed cost collection through the energy charge in the forecast. That resulting value is removed from the amount of energy sales revenue forecast for Schedule 5, with the amount remaining considered to be the energy cost in energy revenue. Energy cost in energy revenue is seasonalized based on CCOS-informed summer/non-summer energy cost ratio. Finally, the energy cost in energy revenue for that season is allocated to the on-peak and off-peak period based on the time-of-use billing determinants, with the per-energy unit cost retaining a four-to-one differential in the summer, and 1.5-to-one differential in the non-summer season. The proposed energy rates from Mr. Anderson's workpapers are reduced for the corresponding per-energy unit seasonal energy cost in energy revenue to calculate a matching differential Schedule 5 FCE rate. The process is replicated for the FCE-DIST for new Schedule 5 customers. Page 5 of Exhibit No. 50 is the workpaper supporting derivation of Schedule 5 FCE and FCE-DIST rates.

Q. How do the FCC and FCE computed in this filing compare to the FCC and FCE established in the Company's last general rate case, IPC-E-11-08?

A. Both the FCC and FCE rates are greater than those currently in effect, which were established using the functionalized classified revenue requirement data in the Company's last filed general rate case, Case No. IPC-E-11-08. The Company has made significant investments in its infrastructure since that time, and the newly calculated FCC and FCE rates reflect those fixed costs that are being recovered through the Residential and Small General Service energy charges.

VIII. SPECIAL CONTRACT CUSTOMERS

Q. Please provide an overview of the Company’s Special Contract customers and how rate design was developed.

A. There are six Special Contract customers and associated rate design proposals included in my testimony. First, I will review rate design proposals for Idaho Power’s three long-standing Special Contract customers, Micron, Simplot Pocatello (Schedule 29), and the United States Department of Energy (“DOE”). Second, I will discuss development of rates for J. R. Simplot Company Caldwell, Idaho (“Simplot Caldwell”) (Schedule 32), whose 2015 Special Contract became active at the end of April 2023 when it exceeded the 20 MW threshold for it to become effective. Finally, I will describe CCOS methodology and rate design for future Special Contract customers Brisbie, LLC (“Brisbie”) and Lamb Weston.

Q. What are the Company’s rate design proposals for the long-standing Special Contract customers, Micron, Simplot Pocatello, and the DOE?

A. The Company is proposing to maintain the current rate structures for the active Special Contract customers Micron, Simplot Pocatello, and DOE, but move the rate design components toward CCOS-informed amounts when increasing forecast collections to recover the revenue requirement shown on Exhibit No. 48. This includes reestablishing the Contract Demand charge for Micron and Simplot Pocatello based on the same methodology the Company recently included in the Brisbie[11] and Lamb Weston contracts.

Q. Please describe the derivation of Micron's and Simplot's Pocatello Contract Demand rates.

A. Consistent with the method most-recently reviewed by the Commission as a reasonable basis for Contract Demand rates approved for Brisbie, and proposed for new Special Contract customer Lamb Weston, I propose Micron and Simplot Pocatello's Contract Demand rate is based on costs derived from the Company's Open Access Transmission Tariff ("OATT") rate effective October 1, 2022. The OATT-based Contract Demand reflects the reservation cost that any other customer would pay on Idaho Power's system. To account for collection of costs by the Contract Demand charge, the Billing Demand rate is adjusted to collect any remaining fixed costs not collected through the Contract Demand charge.

Q. What other rate design elements for Micron, Simplot Pocatello, and DOE are proposed to be updated based on CCOS results?

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[11] *In the Matter of Idaho Power's Application for Approval of Special Contract and Tariff Schedule 33 to Provide Electric Service to Brisbie, LLC's Data Center Facility*, Case No. IPC-E-21-42, Goralski DI, p. 13.

A. I propose that the energy rate for Micron, Simplot Pocatello, and DOE match the CCOS-informed energy rate. This proposed change aligns rate design with cost causation by recovering only variable costs through the energy charge.

Q. Have you included rate design workpapers for Micron, Simplot Pocatello, and DOE?

A. Yes, Exhibit No. 51 includes rate design workpapers for all six Special Contract customers, current and future.

Q. Please describe the Simplot Caldwell Special Contract pricing and CCOS analysis.

A. As noted earlier, in late April 2023 Simplot Caldwell crossed the 20 MW customer load threshold to activate their Special Contract. Idaho Power endeavors that the GRC test year uses the best information available to the Company at the time of development. For Simplot Caldwell, while their Special Contract was approved in 2015, prior to April, Simplot Caldwell had not previously exceeded the threshold to begin taking service under their Special Contract rates. Because historical customer usage has remained slightly below their forecast usage and they remained a Schedule 19 customer since approval of the Special Contract, Idaho Power included Simplot Caldwell as part of the Schedule 19 customer class in the 2023 GRC test year load forecast, consistent with customer load until late April 2023.

For Simplot Caldwell, I completed pricing analysis by first removing their Schedule 19 load statistics from the CCOS study, and then added back their customer-provided Special Contract forecast load as an individual customer to complete cost assignment. This is similar to the approach Idaho Power has utilized when pricing new Special Contract customers between GRC, which is in alignment with the Commission's direction provided in Case No. IPC-E-13-23.[12]

Q. Was additional consideration required as part of developing Simplot Caldwell’s proposed rate design?

A. Yes. It’s important to distinguish the rates and revenue collection forecast for Simplot Caldwell in the 2023 GRC test year, which are based on Schedule 19 rates and a lower, historical usage profile, versus the higher load forecast assumptions for cost assignment as a Special Contract. In the CCOS analysis, the historical basis Simplot Caldwell collections under Schedule 19 are approximately $6.7 million, while the revenue requirement based on their higher, Special Contract load forecast is

[12] *In the Matter of the Application of Idaho Power Company for Approval of a Special Contract with J.R. Simplot Company*, Case No. IPC-E-13-23, Order No. 33038 at 12 (May 19, 2014) (". . . we find that a rate utilizing cost-of-service as a starting point for negotiation is consistent with prior Commission Orders and is fair, just and reasonable.")

$9.97 million. However, because Simplot Caldwell has existing Schedule 32 rates, rate design was evaluated by using current Schedule 32 rates applied to the higher, Simplot Caldwell load forecast used in the completion of the Special Contract CCOS cost assignment.

Q. What is the resulting revenue requirement change and proposed rate design for Simplot Caldwell?

A. I propose to increase Simplot Caldwell's revenue requirement by $6,518 to bring them up to CCOS results, as revenue collection under existing Schedule 32 rates and the forecast Special Contract load are nearly aligned with Simplot Caldwell's cost assignment. Consistent with rate design proposed for Micron and Simplot Pocatello, I propose to update Simplot Caldwell's Contract Demand rate to be OATT-based, and for the energy rate to match CCOS.

Q. How was pricing developed for future Special Contract customer Lamb Weston, which is an Idaho Power tariff Schedule 19P customer today?

A. Idaho Power recently filed an application to enter into a Special Contract with Lamb Weston in recognition of their forecast load exceeding 20 MW in July 2023.[13] However, Lamb Weston's current load is less than 20 MW, and the 2023 CCOS test year data includes Lamb Weston

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[13] *In the Matter of Idaho Power's Application for Approval of Special Contract and Tariff Schedule 34 to Provide Electric Service to Lamb Weston, Inc.*, Case No. IPC-E-23-18, filed May 23, 2023.

as part of Schedule 19 load statistics, consistent with the level of service they currently receive from Idaho Power.

Similar to Simplot Caldwell, I completed pricing analysis by first removing Lamb Weston's Schedule 19 load statistics from the CCOS study, and then added back their future, customer-provided Special Contract steady-state forecast load as an individual customer to complete cost assignment.

Q. Why didn't the Company include Lamb Weston as a Special Contract customer in the GRC test year to develop rates?

A. Lamb Weston is in the process of a plant expansion at its facility in American Falls and is forecast to exceed the Schedule 19 service eligibility threshold in the second half of 2023 but not complete expansion until mid-2024. Due to uncertainty associated with the exact timing of that expansion, it is appropriate to include Lamb Weston's forecast Special Contract system utilization in a future GRC test year once that usage has been achieved.

If Lamb Weston was removed from the Schedule 19 test year load statistics but remained a Schedule 19 customer after the GRC, the total Schedule 19 class would be under-assigned costs, which would instead be allocated to all other Idaho Power customer classes. There is inherent regulatory lag when pricing new, proposed Special Contract customers and the future point in time when all customer rates are re-balanced. The process Idaho Power followed to price Lamb Weston's Special Contract rates incorporates the best-known, historical information for this customer at the time of GRC filing.

Q. Please describe Lamb Weston's rate design components.

A. As described in more detail in the Company's recent filing for Commission approval of the Lamb Weston Special Contract, Case No. IPC-E-23-18, Lamb Weston's Special Contract rates incorporate a two-block, embedded and marginal-cost-based pricing structure. Block 1 represents the first 20 MW of Lamb Weston's load and is priced at Schedule 19 – Primary retail rates, and Lamb Weston' load exceeding 20 MW is priced on an embedded cost basis for capacity and marginal cost basis for energy. Because block 1 references Schedule 19 rates, I propose mirroring the rates proposed by Mr. Anderson for Schedule 19. The marginal energy cost portion of Lamb Weston's second block is based on an annual power supply cost forecast consistent with the PCA test year, with proposed marginal cost rate updates to occur at an annual interval in the spring with updated effective marginal energy rate each June 1st. My rate design focuses on the block 2 demand charge, which is the sole component that is determined by

CCOS for Lamb Weston as a class of one.

Q. What is the resulting proposed block 2 Billing Demand Charge for Lamb Weston?

A. Lamb Weston's block 2 Billing Demand is proposed to be $23.80 per kW. This represents recovery of Lamb Weston's CCOS revenue requirement, which will not be recovered under either block 1 rate components or the Contract Demand charge.

Q. How was pricing for Brisbie developed for their Special Contract rates?

A. Brisbie is forecast to come online beyond the test year period and as a result, no 2023 CCOS customer class adjustment was necessary to remove test year load for Brisbie. Similar to the methodology described in my testimony in the case to establish the current Brisbie, Schedule 33 rates,[14] for the loads that fall under the embedded portion of Brisbie's second block, Brisbie received their load ratio share of embedded capacity costs for a 30 MW steady-state operation assumption.

Brisbie's block 1 rates are fully-embedded and based on Schedule 19 – Transmission retail rates, which have been updated to match the proposed rates for Schedule 19

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[14] *In the Matter of Idaho Power's Application for Approval of Special Contract and Tariff Schedule 33 to Provide Electric Service to Brisbie, LLC's Data Center Facility*, Case No. IPC-E-21-42, Goralski DI, p. 21-42.

provided by Mr. Anderson. Following the terms of the Brisbie Special Contract, the Contract Demand Charge, and Daily Excess Demand Charge have been updated based on the OATT rates in effect October 1, 2022. The remainder of Brisbie's block 2 rates are contractually established in the Brisbie Special Contract and follow an update schedule independent of updates to the Company's CCOS study.

Q. What is the resulting proposed block 2 Billing Demand Charge for Brisbie?

A. Brisbie's block 2 Billing Demand is proposed to be $22.07 per kW. This represents recovery of Brisbie's CCOS revenue requirement which will not be recovered under either block 1 rate components or the Contract Demand charge.

IX. SCHEDULE 20 PRICING

Q. Does the Company currently have any Schedule 20 customers, or are any included in the 2023 test year?

A. No. While Idaho Power continues to respond to prospective customers that are exploring service under Schedule 20, there are no active customers taking service under Schedule 20, thus none were included in the 2023 test year.

Q. Please provide an update on any Schedule 20-related active Commission proceedings.

A. As directed by the Commission, on December

28, 2022, Idaho Power filed an Application recommending two proposals for the Commission's consideration on what, if any, compensation for mandatory interruption should be applicable to Schedule 20 customers.[15] The case is currently ongoing with a deadline for Staff and public comments of June 7, 2023, and a June 21, 2023, Company Reply Comment deadline.

Q. Is the Company proposing any changes to Schedule 20 rates as part of this GRC?

A. Yes. While the Company believes embedded rate components should remain based on underlying Schedule 9 and 19 rates as designed until sufficient Schedule 20 customers have joined Idaho Power's system to complete class-specific cost assignment, Idaho Power recommends updating the marginal energy component basis of Schedule 20, and aligning to the time-of-use periods with those proposed for Schedule 9 and 19.

As recommended by Staff,[16] and adopted by the Commission,[17] the Company agreed[18] that evaluation and comparison of methods other than DSM Avoided Cost Averages

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[15] *In the Matter of Idaho Power's Application for Authority to Establish Compensation for the Mandatory Interruption Requirement of Schedule 20 – Speculative High-Density Load*, Case No. IPC-E-22-30.

[16] *In the Matter of the Application of Idaho Power Company for Authority to Establish a New Schedule to Serve Speculative High-Density Load Customers*, Case No. 21-37, Staff Comments, p. 6.

[17] Case No. IPC-E-21-37, Order 35428, p. 7.

[18] Case No. IPC-E-21-37, Idaho Power Reply Comments, p. 5.

for setting the Schedule 20 energy rates should be completed prior to filing the Company's next (this) GRC. An evaluation is critical to ensure that referenced marginal prices best reflect costs the Company is actually incurring and are recovered through the PCA, which would not be collectable from Schedule 20 as the PCA rate does not apply to Schedule 20 energy sales priced at a marginal rate.

Idaho Power met with Staff on January 20, 2023, and again on February 2, 2023, to discuss the results of Idaho Power's evaluation and to solicit Staff's feedback. Subsequent to the two discussions, Staff provided a memo, included as Exhibit No. 52, outlining five general criteria that should be considered when developing marginal cost-based customer energy rates:

- The resources used in a model for determining marginal cost should be based on the resources that are highly likely to exist during the rate period.
- The amount of incremental load used to determine the marginal cost rate should reflect the amount of incremental load for the portion of load that will be priced at marginal cost.
- The marginal cost rates should have enough granularity to reflect time difference (e.g. seasonality, time of day) value of Marginal

Cost within the Company’s system to provide accurate price signals.

- If the marginal cost rates are based on a forecast, due to the lack of marginal costs being trued-up in the PCA, they should be updated often enough that they reflect current conditions or find a way to true up the marginal cost to actual marginal cost.
- If market costs are used, cost of transmission transaction and wheeling costs should be included.

Q. What marginal cost basis does Idaho Power propose for Schedule 20’s energy rates?

A. In replacement of the current DSM Avoided Cost Average-based marginal rates, the Company proposes to use an AURORA-based method. This achieves several of the criteria noted in Staff’s memo including granularity to reflect time differences, costs based on resources likely to exist during the rate period, and more frequent updates to reflect more current market conditions than DSM Avoided Cost Averages.

The marginal cost of energy is determined from the simulated hourly operation of the Company’s power supply system over forecast hydro conditions. Net power supply expenses are first quantified using the Company’s expected load for the test year, then an incremental load increase is added to determine the resulting increase in power supply expenses and generation. The difference in monthly power supply expenses between the initial and subsequent simulation is divided by the difference in generation to produce a marginal cost per kWh.

Q. What are the resulting marginal energy rates, and at what interval does the Company propose to make updates?

A. The proposed seasonal, time-of-use marginal rates are as follows:

TABLE 6

Proposed Seasonal – Time of use Marginal Rates

SONP ($/kWh)	$ 0.068108
SMP ($/kWh)	$ 0.095308
SOFP ($/kWh)	$ 0.050374
NSONP ($/kWh)	$ 0.048629
NSMP ($/kWh)	$ 0.068321
NSOFP ($/kWh)	$ 0.057180

The Company proposes Schedule 20 energy rates be updated annually on June 1 using a forward test year consisting of the 12-month period April through the subsequent March, consistent with power cost spring filings.

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

A. Yes, it does.

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DECLARATION OF PAWEL P. GORALSKI

I, Pawel P. Goralski, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Pawel P. Goralski. I am employed by Idaho Power Company as a Regulatory Consultant in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 36 through 52 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: Pawel P. Goralski
PAWEL P. GORALSKI