BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF IDAHO POWER COMPANY FOR	)	CASE NO. IPC-E-23-11
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	
IN THE STATE OF IDAHO AND FOR	)	
ASSOCIATED REGULATORY ACCOUNTING	)	
TREATMENT.	)	
	)	

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

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

A. My name is Timothy E. Tatum. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as Vice President of Regulatory Affairs.

Q. Please describe your educational background.

A. I earned a Bachelor of Business Administration degree in Economics and a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electric Industry," a course offered through the New Mexico State University's Center for Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Edison Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course." In 2012, I attended the Utility Executive Course ("UEC") at the University of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 in the Company's Customer Service Center where I handled customer phone calls, customer-related transactions, and general customer account maintenance in the areas of billing and metering.

In June of 2003, 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") expenses 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 Integrated Resource Plan.

In August 2004, I accepted a position as a Regulatory Analyst and in August of 2006, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities included the development of complex financial studies to determine revenue recovery and pricing strategies, including preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to Manager of Cost of Service, and in 2011, I was promoted to Senior Manager of Cost of Service and oversaw the Company's cost-of-service activities, such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

In March 2016, I was promoted to Vice President of Regulatory Affairs. As Vice President of Regulatory Affairs, I am responsible for the overall coordination and direction of the Regulatory Affairs Department, including development of jurisdictional revenue requirements and class cost-of-service studies, preparation of rate design analyses, and administration of tariffs and customer contracts.

I. <u>CASE OVERVIEW</u>

Q. What role did you play in the preparation of the general rate case ("GRC")?

A. My role in the preparation of the GRC was to oversee, manage, and coordinate the filing and to make the policy decisions related to regulatory matters in consultation with Ms. Lisa Grow, our Company's President and Chief Executive Officer, along with other senior officers within Idaho Power.

Q. What is Idaho Power's requested revenue increase this case?

A. The Company is requesting rate relief of approximately $111.3 million, which is net of a corresponding proposed Power Cost Adjustment ("PCA") decrease of $173.4 million and a reduction to annual Energy Efficiency Rider collection of $3.5 million. If approved, this request would result in an overall increase to adjusted base revenue of 8.61 percent effective January 1, 2024. The Company's request is based on a proposed rate of return of 7.702 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 4.895 percent cost of debt, and a 10.40 percent return on equity ("ROE").

Q. What is the Company's test year?

A. The test year is the 12 months ending December 31, 2023.

Q. Why is Idaho Power requesting a corresponding PCA decrease of $173.4 million in this case?

A. Idaho Power's current Idaho base rates collect approximately $300 million annually to fund normalized or "base level" net power supply expense ("NPSE"). This level of NPSE collection authorized by Order No. 33000 in Case No. IPC-E-13-20 became effective June 1, 2014, based on a 2013 calendar year. Since that time, the Company's normalized NPSE has increased largely because of load growth and changes in fuel costs, market energy prices, and increased power purchase agreement costs. Currently, incremental NPSE over the base level NPSE established in 2014 are collected annually through the PCA forecast component. Because the Company's requested Idaho-jurisdictional revenue requirement in this case reflects updated base level NPSE based on the 2023 test year, the Company is requesting a corresponding decrease in annual

PCA collection to ensure customers do not pay twice for the same NPSE. Simply put, this necessary PCA reduction will facilitate the transfer of base level NPSE collection from the PCA into base rates.

Q. How is energy efficiency currently funded at Idaho Power?

A. The Company's energy efficiency activities, also referred to as DSM, are primarily funded through the Energy Efficiency Rider, Schedule 91 ("Rider"), which is applied as a fixed percentage of each customer's billed base revenue. Idaho Power is currently authorized to collect 3.1 percent of base revenue annually through the Rider.

Q. What is the Company's proposal regarding annual Rider collection?

A. Idaho Power is proposing to transfer approximately $3.5 million in ongoing Rider-funded labor costs into base rates, while otherwise maintaining the same level of annual DSM funding as measured in dollars that exists today. To achieve this goal, the Company is proposing a decrease in Rider collection from the current 3.1 percent to 2.25 percent.

Q. Why is the Company proposing to transfer approximately $3.5 million in ongoing DSM labor costs in this rate filing?

A. There are two reasons for this proposal. First, energy efficiency has been a core business activity at Idaho Power for over 20 years, since the Rider was established in 2002. At the time the Rider was established, the Company identified all incremental costs associated with implementing and managing new DSM programs, including incremental labor-related costs, to be funded through that mechanism. Over time, DSM program management and administration staffing has reached a relatively steady state, both from a cost and head-count perspective. For these reasons, it is appropriate to treat DSM labor the same as any other Company labor costs for ratemaking purposes.

Secondly, DSM labor costs have been a point of concern for the Commission Staff ("Staff") in past prudence review cases. My understanding of Staff's concern is that Rider-funded labor, under the annual prudence review process, has allowed for recovery of labor-related costs annually without the rigorous, comprehensive review applied in general rate cases. By treating DSM labor the same as all other labor costs for cost recovery purposes, Idaho Power believes this will address Staff's concern.

Q. What is the implication of this proposal for energy efficiency activities going forward?

A. The proposed reduction in energy efficiency

Rider funding will have no impact on the Company's pursuit of cost-effective energy efficiency activities. This adjustment is only intended to transfer the collection of energy efficiency labor costs to base rates and to ensure that the increase to base rate revenue requested in this case does not result in an increase to the annual revenue collected under the Rider. As always, Idaho Power will monitor the need for energy efficiency funding and will propose adjustments to funding levels as warranted to allow for the Company's continued pursuit of all cost-effective energy efficiency.

Q. Is Company seeking any specific regulatory treatment related to wildfire mitigation and insurance costs as part of this case?

A. Yes. Idaho Power requests the Commission continue to authorize the Company to defer incremental wildfire mitigation and insurance costs as measured from a new base level of costs established in this case. This proposed treatment is consistent with the authority granted by the Commission in Case Nos. IPC-E-21-02 and IPC-E-22-27, with certain limited modifications.

In this case, the Company is only requesting authority to defer incremental costs associated with two previously authorized cost deferral categories of vegetation management and insurance.

Q. Why is Idaho Power requesting ongoing deferral authority for incremental vegetation management and insurance expenses above the baseline levels set in this case?

A. As discussed in the Direct Testimony of Company Witness Mr. Brian Buckham, insurance costs have increased in recent years and continue to rise. Further, insurance costs are increasingly difficult to forecast due to price volatility. While Idaho Power undertakes significant efforts to ensure it receives the greatest insurance value possible for its customers, the Company is largely a price-taker in the insurance market and must absorb price increases as insurers raise premiums due to losses. Therefore, the Company believes it is appropriate to request a new baseline level of insurance in rates and also to establish a new deferral to capture incremental insurance premium costs above the new baseline.

Similarly, as addressed in detail in the Direct Testimony of Company Witness Mr. Mitch Colburn, vegetation management costs continue to rise. These costs constitute the largest single expense associated with the Company's wildfire mitigation efforts. As such, the Company requests the authority to continue to defer incremental vegetation management above the new baseline established in this case until such a time that these costs stabilize.

Q. Is the Company requesting new deferral authority for wildfire-mitigation related capital items?

A. No. Because the Company has already made the majority of necessary incremental capital investments related to the implementation of its Wildfire Mitigation Plan, there is no longer a need to defer related depreciation expense amounts.

Q. Is the Company requesting any other specific regulatory treatment as part of this case?

A. Yes. The Company has several requests for specific regulatory treatment and necessary regulatory accounting as part of this case that I will cover in detail later in my testimony. At the end of my testimony, I will provide a summary listing each of those requests for clarity and transparency.

II. TEST YEAR

Q. How did the Company prepare its test year in this proceeding?

A. Idaho Power prepared its 2023 test year in this case using the same general forecast methodology used in the Company's last two general rate cases, IPC-E-08-10 and IPC-E-11-08. The Company's test year methodology starts with actual 12-month financial results adjusted to include typical and traditional ratemaking adjustments consistent with a historical test year. The adjusted 2022 actual financial information was then further adjusted to reflect 2023 results through the use of known and measurable adjustments appropriate for the particular revenue, expense, or asset classification.

Q. What attributes should be considered when selecting a test year?

A. In practice, in every rate case, a test year must be selected. Whether the test year selected is historical, future, or some hybrid, the most important attribute of the selected test year should be that it accurately reflects the best expectation of the cost of service.

Regardless of which test year is adopted, the ratemaking process is inherently prospective and requires reliance upon projections. Whether the test year is completely historical or based totally on future results, the ratemaking process requires an informed determination of what conditions will prevail in the future. As of the date of filing, Idaho Power has used its best financial and operational information to construct its forecast test year.

Utility commissions and policy makers throughout the country, and particularly in the West, are increasingly recognizing that in times of high inflation and heavy construction, future test years are necessary to allow utilities a reasonable opportunity to earn their authorized rate of return. Utilities that operate in a period of rapid expansion and rate base growth will chronically under-earn if test years are historical in nature and fail to synchronize the matching of expenses and revenues.

Ultimately, Idaho Power must apply a test year approach that is both timely and reflective of the costs that the Company can reasonably expect to incur going forward. A historical test year is by definition not timely and may not be a reflection of costs going forward. Similarly, a test year based on a reasonable forecast may be more indicative of the costs the Company will be experiencing during the time rates are in place, thereby reducing the effects of "regulatory lag".

Q. Why is regulatory lag such a critical issue to Idaho Power at this time?

A. During periods of escalating costs where marginal costs are higher than average costs, new rates are already inadequate by the time they go into place. If this situation continues for a prolonged period of time, the Company will be denied a reasonable opportunity to earn its authorized rate of return. The effects of regulatory lag are particularly pronounced in periods where the Company is engaged in capital-intensive projects and where interest rates to finance capital projects are rising.

Q. Is regulatory lag always harmful to a utility?

A. No. The impact of regulatory lag is dependent upon the situation – if overall revenue growth is keeping pace with cost escalation, and the Company is not engaged in capital-intensive projects and procuring debt and equity financing for those projects, then the Company is not typically harmed by regulatory lag. Unfortunately, Idaho Power is not in that situation currently, and will not likely be for the foreseeable future.

III. REVENUE REQUIREMENT MITIGATION ADJUSTMENTS

Q. Did you receive any specific instructions from Ms. Grow in preparing this general rate case filing?

A. Yes. In recognition of the broader economic conditions and concern for the impact that any rate increase has on customers, Ms. Grow asked me to identify specific areas where the Company could reduce the requested increase at this time. As a result, I identified the following areas where the Company is not asking for incremental increases or has otherwise taken action to minimize the overall requested revenue increase:

- Reduce return on equity ("ROE") from the recommended level of 10.60 percent to 10.40 percent;
- Hold test year non-labor operations and maintenance ("O&M") expenses to the 2022 actual level with

the exception of a limited number of known and measurable adjustments;

- Maintain the North Valmy Power Plant ("Valmy") and the Jim Bridger Power Plant ("Bridger") non-fuel coal-related cost recovery at current levels, with the exception of collection related to previously deferred revenue requirement amounts;
- Minimize the current revenue increase related to wildfire mitigation and pension costs by leveraging the existing cost recovery mechanisms; and
- Delay recovery of the revenue requirement associated with the 120 megawatts ("MW") of battery storage resources to be online in 2023 with interim earnings support from the associated investment tax credits generated from the battery storage resources.

Q. How did the Company arrive at its recommended mitigated ROE of 10.4 percent?

A. After discussions with Mr. Buckham, Senior Vice President and Chief Financial Officer, regarding Ms. Grow's directive to mitigate our rate relief request, the Company decided to apply an ROE that is at the lower end of the range provided by our outside ROE expert. Mr. Buckham believes this recommendation represents the minimum required ROE necessary to not weaken the Company's ability to attract capital at favorable and customer-beneficial rates in the current uncertain and volatile financial markets.

Q. What steps did the Company take to minimize the level of non-labor O&M included in the test year and what were the results?

A. The Company chose to hold test year non-labor O&M expense to the 2022 actual level, with the exception of a limited number of known and measurable adjustments. As discussed by Ms. Grow in her testimony, the Company has a strong track record of managing its O&M expenses, and as a result has achieved an average annual O&M growth rate of <u>only one percent between 2012 and 2022</u>. After applying all known and measurable adjustments to the 2022 actual financial results, Idaho Power's proposed test year non-labor O&M is within approximately $340 thousand of the 2022 expense level.

Q. What is the Company's recommendation regarding the recovery of non-fuel coal-related revenue requirements associated with the Valmy and Jim Bridger power plants?

A. Because the Commission has previously established separate cost recovery mechanisms for these components of the Valmy and Bridger plants in Order Nos. 33771 and 35423, respectively, the Company is proposing to maintain the current level of recovery as previously authorized by the Commission with one exception. In addition to maintaining recovery of the amounts already included in customer rates, the Company is proposing to increase collections only related to the Bridger plant to include revenue requirement amounts that the Commission chose to defer for later recovery in Order No. 35423.

Q. What incremental Bridger-related cost recovery is the Company requesting in this case?

A. Idaho Power is requesting recovery of the full annual levelized revenue requirement approved in Case No. IPC-E-21-17 and amortization of previously deferred levelized revenue requirement amounts. The total incremental annual Bridger-related cost recovery included in this case is approximately $10.7 million.

Q. What is the Company’s recommendation regarding the test year level of wildfire mitigation costs?

A. Idaho Power is proposing to hold test year levels of wildfire mitigation costs to 2022 actual cost. Further, the Company is requesting amortization into rates of previously deferred wildfire mitigation costs, excluding deferred vegetation management costs, over a seven-year amortization period.

Q. Why is the Company requesting to exclude deferred vegetation management costs as part of its amortization request in this case?

A. As introduced earlier, vegetation management costs represent the largest single cost component of the Company’s overall wildfire mitigation costs. As a rate mitigation measure, the Company chose to postpone the recovery of deferred vegetation management costs and instead continue to utilize the deferral account authorized by the Commission in Order Nos. 35077 and 35717 issued in Case Nos. IPC-E-21-02 and IPC-E-22-27, respectively. By setting cost recovery at the 2022 level, the Company anticipates that the need to defer incremental amounts over time may diminish.

Further, the Company is hopeful that advances in new vegetation monitoring technology may eventually reduce annual vegetation management costs, allowing for deferred amounts to be offset by future cost reductions, thereby reducing the deferral balance. The Company will continue to closely monitor its vegetation management costs and will report back to the Commission in a future proceeding if an adjustment to related cost recovery is warranted.

Q. How did the Company arrive at its recommended test year pension cost recovery amount?

A. To arrive at its proposed test year pension cost recovery amount, the Company considered several factors, including its expected ongoing annual cash contributions to the pension plan and the cost recovery mechanism and balancing account approved by Commission

Order No. 31003 issued in Case No. IPC-E-09-29. In recent years, the Company has been contributing approximately $40 million annually to fund its pension plan. While the annual minimum required funding level fluctuates, this annual level of funding has represented a levelized or normal level of required funding. The Company's current rates include recovery of approximately $17 million a year. Annual differences between the $40 million in annual cash contributions to the pension plan and the $17 million of recovery through rates have been deferred as authorized by Order No. 31003. Rather than request recovery of the full $40 million of annual pension funding, as a rate mitigation measure, the Company is proposing to increase the current $17 million in annual pension cost recovery to approximately $35 million, and to continue to defer any differences between collection and plan contributions through the pension balancing account. If interest rates continue to stay at current elevated levels or higher, the associated discount rates used to determine annual pension funding requirements are more likely to drive required plan contributions down. While not known at this time, the Company is hopeful that the $35 million in annual pension cost recovery may ultimately provide sufficient revenue to cover the ongoing required cash contributions to the plan while also serving to reduce the regulatory asset in the balancing account.

Q. What is the Company’s proposal regarding deferred recovery of the 120 MW battery storage project to be online in 2023?

A. As an additional rate increase mitigation measure, the Company is proposing to delay recovery of the revenue requirement associated with the 120 MW of battery storage resources to be online in 2023, with interim earnings support from the associated federal investment tax credit (“ITC”) generated from the battery storage resources. More specifically, the Company is requesting authorization to 1) move to the Accumulated Deferred Investment Tax Credits ("ADITC")/Revenue Sharing Mechanism an additional amount of ITC equal to the incremental ITC generated from the Company’s investment in the 2023 battery storage projects, and 2) increase to the maximum allowed annual accelerated amortization amount by a level of ADITC equal to the actual revenue requirement of the battery storage projects in any applicable year plus the current annual $25 million cap authorized by Order No. 30978 issued in Case No. IPC-E-09-30.

Q. Is the Company proposing to exclude the 120-MW battery storage projects from rate base as part of this proposal?

A. No. The Company is requesting a full prudence review of the 120-MW battery storage projects as part of this case, with the goal of receiving Commission approval to include the Idaho jurisdictional portion of the investment in its Idaho rate base. As part of this rate impact mitigation measure, the Company is proposing to include in the final Idaho jurisdictional revenue requirement a temporary credit adjustment equal to the Idaho-jurisdictional share of the 120-MW battery revenue requirement. This credit would remain in place until the Company is authorized to recover the associated revenue requirement in a future general rate case or other applicable revenue requirement proceeding.

Q. Please provide an overview of the ADITC/Revenue Sharing Mechanism.

A. Since 2009, the Company has been subject to an ADITC/Revenue Sharing Mechanism that includes provisions for the accelerated amortization of ADITC to help achieve a minimum specified percent Idaho-jurisdiction return on year-end equity ("Idaho ROE"), currently set at 9.4 percent. The mechanism also provides for the potential sharing between Idaho Power and Idaho customers of Idaho-jurisdictional earnings in excess of a 10.0 percent Idaho ROE. Under the current mechanism, the ADITC and sharing thresholds are to be reset at a general rate case to align the sharing threshold with the then-authorized ROE and the use of accelerated amortization of ADITC at 95 percent of the authorized ROE.

Q. What is the expected dollar value of the ITC generated by the 120-MW battery storage investment?

A. The Company expects the 120 MW of battery storage projects will generate approximately $45 million of new federal ITC based on an assumption that the ITC will be equal to 30 percent of total project cost under Section 48 of the Internal Revenue Code.

Q. What is the annual revenue requirement associated with the 120 MW battery storage projects?

A. The test year revenue requirement associated with the 120 MW battery storage projects is $21,149,854. When considering the approximately $45 million of new federal ITC associated with the investment, the ITC represents approximately two years of the annual revenue requirements for the batteries.

Q. Under the Company’s proposal, what will happen to the ITC generated from the 120-MW battery projects, if they have not been amortized prior to the time the Company is allowed to recover the cost of the batteries in customer rates?

A. The Company proposes that the ITC remain available for accelerated amortization under the provisions of the ADITC/Revenue Sharing Mechanism until fully amortized - either on an accelerated basis or according to the standard amortization schedule tied to the depreciable life of the associated asset. Both maintain the Company’s long-standing compliance with federal and state ITC normalization rules.

Q. Does the $21,149,854 test year revenue requirement include an offsetting annual benefit of the amortization of associated ITC?

A. Yes. The $21,149,854 test year revenue requirement includes the impacts of ITC using the standard amortization schedule that ties to the depreciable life of the associated asset. An ITC amortization benefit would remain in future associated revenue requirement calculations until the ITC are fully amortized.

Q. Aside from deferring the rate impact of the battery projects, what other benefits will customers receive?

A. Aside from deferring the rate impact of the battery projects, customers will continue to receive the benefits of the ITC for ratemaking purposes until the ITC has been fully amortized as I previously described. As has been the case since the ADITC/Revenue Sharing Mechanism was first implemented, customer rates have continued to reflect the offsetting benefit of ITC amortization and, as of December 31, 2022, the Company has not utilized any of the currently available ADITC for accelerated amortization. In this instance, customers are guaranteed to get the benefits of service from the 120 MW of batteries at no cost in the near-term, while preserving an opportunity to still benefit from that ITC in future ratemaking proceedings.

IV. WITNESS LIST

Q. What was your level of involvement with the preparation of the testimony and exhibits presented by the other Company witnesses?

A. I discussed the content and preparation of the witnesses' testimony and exhibits with Ms. Connie Aschenbrenner (Rate Design Senior Manager), Mr. Matthew Larkin (Revenue Requirement Senior Manager), and Mr. Donovan Walker (Lead Counsel), as well as Ms. Lisa Nordstrom (Lead Counsel) and Ms. Megan Goicoechea Allen (Corporate Counsel).

Q. Please provide an overview of the Company's general rate case filing.

A. The Company begins the presentation of its case with Ms. Grow's testimony, who provides a general overview of the Company and addresses Idaho Power's current financial and operating situation and need for general rate relief. My testimony is next and covers the regulatory policy matters related to the development of the general rate case.

Mr. Eric Hackett, Projects and Design Senior Manager, discusses the growth in the Company's generation-related rate base since the completion of the Company's last general rate case, up to and including major projects expected to be completed during the 2023 test year. He presents the prudent nature of these investments, detailing why they are needed to ensure Idaho Power's generation fleet is robust and well-positioned to provide continued safe, reliable service to customers. Mr. Hackett is also the witness who presents the costs associated with, and an operation overview of, the 120-MW battery projects placed into service in 2023.

Ms. Lindsay Barretto, 500 kV and Joint Projects Senior Manager, discusses the prudent nature of investments made at Bridger and Valmy since the Company's last prudence determinations before the Commission.

Mr. Mitch Colburn, Vice President of Planning, Engineering and Construction, discusses investments the Company has made in the electrical grid to ensure the provision of safe, reliable service to customers. Specifically, Mr. Colburn details Idaho Power's recent history of reliability and system performance that demonstrates a thoughtful approach to grid construction and maintenance. He also presents specific investments included in the Company's 2023 test year that demonstrate the

Company’s prudent investment in the electrical grid at the transmission and distribution levels. Finally, Mr. Colburn reviews the Company’s wildfire mitigation efforts and associated capital and O&M expenditures.

Mr. James “Bo” Hanchey, Vice President of Customer Operations and Chief Safety Officer, describes the Company’s Safety First culture and ongoing efforts to enhance our customers’ overall experience with the Company. Mr. Hanchey also describes the Company’s advancements in energy efficiency as well as customer relations activities and related technology upgrades.

Ms. Sarah Griffin, Vice President of Human Resources, provides justification for the labor and total compensation costs included in the Company’s test year. Ms. Griffin also describes the Company’s overall compensation philosophy and explains why the level of compensation requested in this case is necessary to provide safe, reliable, affordable electricity to customers. As part of this discussion, she also provides the justification for the requested increase in cost recovery related to the Company’s pension plan, which serves as a key component of Idaho Power’s overall compensation package.

The next witness is Mr. Adrien McKenzie, who has been retained by the Company as its ROE expert. Mr. McKenzie discusses risk factors relevant to Idaho Power, performs calculations of ROE appropriate for the Company using standard financial methodologies, and recommends a reasonable ROE range appropriate for Idaho Power. In this proceeding, Mr. McKenzie's ROE range is from 10.10 to 11.10 percent.

Mr. Brian Buckham, Idaho Power Company's Senior Vice President and Chief Financial Officer, builds on Mr. McKenzie's recommendations by more specifically addressing the relevant risk factors impacting the Company. Mr. Buckham selects a 10.40 percent ROE point estimate as the appropriate cost of equity, supports the cost of Idaho Power's long-term debt, and includes the long-term debt and the 10.40 percent ROE in the test year capital structure to derive the Company's proposed overall rate of return.

Ms. Paula Jeppsen, the Company's Forecasting and Planning Director, next testifies to the actual 2022 financial results with standard ratemaking adjustments. Ms. Jeppsen describes the development and application of the methodologies used to prepare the 2022 base financial information and the adjustments to those data associated with deductions to certain expenses not allowed in rates, certain adjustments to expenses and rate base, and other adjustments to revenues, expenses, and rate base related primarily to past Commission orders.

Mr. Matthew Larkin, Revenue Requirement Senior

Manager, describes how the Company utilized the 2022 financial data as presented by Ms. Jeppsen as a starting point from which he made conservative adjustments to derive similar data corresponding to the 2023 test year. Mr. Larkin prepared an exhibit that details the method and rationale for each adjustment he utilized in developing the 2023 test year data. Once he determined the 2023 test year system-level data, Mr. Larkin supervised the preparation of the jurisdictional separation study utilized to determine the Idaho jurisdictional revenue requirement.

Ms. Jessica Brady, Regulatory Analyst, provides the normalized net power supply expenses for the test year and addresses the requisite changes to the Company's PCA as a result of changing the normalized net power supply expenses in Idaho Power Company's base rates.

Ms. Kelley Noe, Regulatory Consultant, incorporates Ms. Jeppsen's financial data, Mr. Larkin's test year adjustments, Mr. Buckham's overall rate of return recommendation, and Ms. Brady's normalized net power supply expenses, along with other necessary inputs, and prepares the jurisdictional separation study ("JSS"). The JSS, as its name states, separates system values for rate base, revenues, and expenses for each state jurisdiction through an assignment and allocation process that is described in detail in Ms. Noe's testimony. One result of the JSS is the

Idaho retail jurisdictional revenue requirement, which is the Company’s best representation of its expected annual cost to serve its Idaho retail customers. The 2023 Idaho jurisdictional revenue requirement is $1,404,314,821. In order to obtain this amount, Idaho’s annual retail revenues will need to increase by $111,304,981 or 8.61 percent.

Ms. Connie Aschenbrenner, Rate Design Senior Manager, describes the Company’s approach to rate design strategy as well as the policy basis for the rate design proposals being made in this case. Ms. Aschenbrenner also presents an overview of the Company’s approach to developing pricing for its on-site generation customers, specifically considering interdependencies between this case and Case No. IPC-E-23-14, which is currently pending before the Commission.

Mr. Pawel Goralski, Regulatory Consultant, uses the Idaho retail jurisdictional output from the JSS as developed by Ms. Noe and further separates costs by customer class and special contract in preparing the Company’s class cost-of-service study (“CCOS”). The study prepared by Mr. Goralski in this case presents an approach most similar to that used by the Company in its last general rate case, with certain modifications and additions. In the Company’s 2008 general rate case, IPC-E-08-10, the Commission approved a cost-of-service methodology termed “3CP/12CP” and the Company subsequently used a similar methodology in its 2011 general rate case, IPC-E-11-08, which was ultimately settled without a Commission decision regarding the filed CCOS. Mr. Goralski used that same CCOS method as the starting point for his CCOS in this case and then applied modifications to the seasonal definition for peak capacity allocation, the classification of baseload resources between demand and energy, and other changes described in his testimony. Mr. Goralski recommends that his CCOS be used as the appropriate starting point for rate spread (the process of spreading the Idaho jurisdictional revenue requirement to the customer classes and special contract customers) and rate design (the ultimate calculation of rates for customers). Mr. Goralski also presents the Company’s rate recommendations for its special contract customers and Schedule 20, Speculative High-Density Load as well as the proposed Fixed Cost Adjustment rates and the corresponding modifications to Schedule 54.

Mr. Grant Anderson, Regulatory Consultant, presents the Company’s proposed rate design and resulting prices for the residential classes, including standard service (Schedule 1), time-of-use (Schedule 5), and residential on-site generation (Schedule 6) and explains the Company’s Residential Price Modernization Plan. Mr. Anderson also presents the rate design proposals for Small General Service On-Site Generation (Schedule 8), Large General Service – Primary and Transmission (Schedule 9P/T) and Large Power customers (Schedule 19).

Mr. Zack Thompson, Regulatory Analyst, presents the rate design proposals for Small General Service (Schedule 7), Large General Service – Secondary (Schedule 9S), Agricultural Irrigation Service (Schedule 24), Dusk to Dawn Customer Lighting (Schedule 15), Street Lighting Service (Schedule 41), Traffic Control Signal Lighting Service (Schedule 42), and Non-Metered General Service (Schedule 40).

Finally, Riley Maloney describes the recommendation for the Company's Standby Service schedules (Schedules 31 and 45) and Alternate Distribution Service schedule (Schedule 46). Mr. Maloney also presents several proposed modifications to the Company's tariff.

V. RATE SPREAD AND RATE DESIGN

Q. What has been Idaho Power's policy with regard to rate spread and rate design proposals?

A. Idaho Power has consistently advocated for the principle that rate spread among the customer classes, and for component pricing within the customer classes, should be primarily cost-based. Accordingly, the Company's ratemaking proposals have traditionally advocated movement toward cost-of-service results that assign costs to those customers that cause the Company to incur the costs. The Company is also committed to providing customers cost-based price signals, which encourage the wise and efficient use of energy. As such, I have directed Ms. Aschenbrenner to design cost-based rate proposals that also encourage increased energy efficiency among the Company's Residential Service, Large General Service, Large Power Service and Irrigation customer groups.

Q. Do the Company's proposals in this case strictly adhere to that objective?

A. No. The Company realizes that there are often other ratemaking objectives, such as rate stability, ability to pay, and mitigating rate shock, that the Commission may consider in making its determination. However, the Company believes that the best starting point for Commission deliberations is an economic one. Nevertheless, because some ratemaking situations may cause abrupt change, Idaho Power has traditionally proposed some limits to the movement toward cost-of-service. The specifics of the Company's proposed rate spread and an exhibit delineating the target revenue requirement for each customer class are contained in Mr. Goralski's testimony.

Q. What guidance did you provide Mr. Goralski regarding cost-of-service constraints applied to the rate spread ultimately recommended?

A. First, I discussed the CCOS prepared for this case with Mr. Goralski and agreed that his recommended CCOS methodology represented the preferred starting point in this proceeding to develop the recommended rate spread. However, this method when applied without constraints, does show a larger impact to a number of customer classes (relative to the overall average increase), most notably Agricultural Irrigation, Schedule 24. Given recent rate pressures and the somewhat subjective nature of cost allocation and year-to-year cost components, I asked Mr. Goralski to run several rate mitigation scenarios to look at the impacts of constraining the rate increase at different levels.

After this review, the Company chose to impose a cap of one and a half times the average revenue change for any customer class or special contract customer exceeding the overall average increase. This level allowed for a reasonable level of revenue movement, while not dramatically impacting the remaining classes that had to make up the shortfall.

Q. How has Idaho Power addressed the cost-based objective in its rate design proposals?

A. This objective has been met by the implementation of seasonal rates for all metered service schedules, and the implementation of rate structures that reflect a greater emphasis on the demand and customer components. The Company also proposes the continuation of mandatory time-of-use pricing for Large Commercial customers taking service at primary and transmission voltages and all Large Power Service customers. In addition, this objective has been met by offering optional time-of-use pricing for Residential and Large General service customers taking service at the secondary voltage level.

Q. Please summarize the Company’s requested Price Modernization Plan.

A. I directed Ms. Aschenbrenner to evaluate and recommend a proposal that would move fixed cost collection from volumetric rates into fixed charges, while mitigating the bill impact to customers. In this case, the Company is proposing the Commission authorize Idaho Power to implement revenue neutral rate changes on January 1, 2025, and January 1, 2026, to achieve this goal. The proposed three-year Price Modernization Plan appropriately mitigates customer bill impacts while reducing reliance on the FCA.

VI. CONCLUSION

Q. Please summarize Idaho Power’s requested revenue increase this case?

A. The Company is requesting rate relief of approximately $111.3 million, which is net of a corresponding proposed PCA decrease of $173.4 million and a reduction to annual Rider collection of $3.5 million. If approved, this request would result in an overall increase to adjusted base revenue of 8.61 percent effective January 1, 2024. The Company's request is based on a proposed rate of return of 7.702 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 4.895 percent cost of debt, and a 10.40 percent ROE. This request was developed using a test year of 12 months ending December 31, 2023.

Q. Will you please summarize the Company's other requests for specific regulatory treatment and/or necessary accounting authority proposed in this case?

A. In addition to approval of the base revenue increase presented in this case and each of the affected tariff schedules, the Company requests the Commission issue an order that includes the following:

1. Approval of a revised Schedule 55, Power Cost Adjustment, reflecting the transfer of certain base level NPSE from the PCA to base rates.
2. Approval of a revised Schedule 91, Energy Efficiency Rider, reflecting the transfer of DSM labor-related cost collection from the Rider into base rates.

3. Approval of a revised Schedule 54, Fixed Cost Adjustment, reflecting the modifications necessary to support the Company’s proposed rate designs.
4. Authorization of the continued deferral of incremental vegetation management and insurance costs in 2024 and beyond as measured from a new base level of costs established in this case.
5. In association with the rate increase mitigation measure proposed in this case, authorization to 1) move to the ADITC/Revenue Sharing Mechanism an additional amount of ITC equal to the incremental ITC generated from the Company’s investment in the 2023 battery storage projects and 2) increase the maximum allowed annual accelerated amortization amount by a level of ITC equal to the actual revenue requirement of the battery storage projects in any applicable year plus the current $25 million cap.
6. Authorization to defer and amortize annual differences between certain periodic maintenance costs at the Langley Gulch and Bennett Mountain natural gas-fired power plants (as described in Mr. Larkin’s testimony).

7. Approval of the Company’s request for its proposed Residential Price Modernization Plan.

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

A. Yes. The proposed rates will allow Idaho Power to continue providing safe, reliable service at reasonable rates while maintaining its financial health.

Q. Does this conclude your testimony?

A. Yes, it does.

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DECLARATION OF TIMOTHY E. TATUM

I, Timothy E. Tatum, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Timothy E. Tatum. I am employed by Idaho Power Company as the Vice President of Regulatory Affairs.

2. On behalf of Idaho Power, I present this pre-filed direct testimony.

3. To the best of my knowledge, my pre-filed direct testimony is 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: Tim Tatum ____________________
Timothy E. Tatum