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February 28, 2024

VIA E-MAIL TO

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. UE 425 – In the Matter of Idaho Power Company, 2024 Annual Power Cost Update.

Attention Filing Center:

Attached for filing in the above-referenced docket is Idaho Power Company's Reply Testimony of Jessica G. Brady (Idaho Power/200-204). A confidential copy of this filing will be distributed to parties bound by General Protective Order No. 23-132.

Please contact this office with any questions.

Sincerely,

Cole Albee

Cole Albee
Paralegal
McDowell Rackner Gibson PC

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IN THE MATTER OF IDAHO POWER COMPANY'S 2024 ANNUAL POWER COST UPDATE	)
OCTOBER UPDATE	)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

JESSICA G. BRADY

February 28, 2024

Q. Are you the same Jessica G. Brady who previously submitted Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your Reply Testimony?

A. The purpose of my Reply Testimony is to respond to the issues raised by Julie Dyck and Dean Ratliff on behalf of the Public Utility Commission of Oregon ("OPUC") Staff ("Staff") in their Opening Testimony. Staff carried out a thorough investigation of Idaho Power's filing, including but not limited to, reviewing the Company's calculations, modeling assumptions, and the final revenue requirement and rate spread methodology. Based on this review, Staff has proposed two adjustments to Idaho Power's 2024 October Update filing. The Company appreciates Staff's thorough investigation of Idaho Power's filing.

Q. Please summarize Staff's proposed adjustments.

A. Staff's first proposed adjustment applies a growth factor to Energy Imbalance Market ("EIM") benefits in each APCU filing, beginning with this year's March Forecast. Staff's second proposed adjustment is a $36.1 million, or 14.3 percent, decrease to the Company's forecast of Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses.[1]

Q. How does Idaho Power respond to Staff's proposed adjustments?

A. Idaho Power has analyzed Staff's calculations and methodologies underlying the proposed adjustments to EIM benefits and PURPA expenses. Based on these analyses, which are described in more detail throughout this testimony, Idaho Power does not agree with either proposed adjustment.

[1] Staff/100, Kim/2, lines 11-16.

EIM Benefits

Q. What is the level of EIM benefits included in this year's October Update?

A. The level of EIM benefits included in this year's October Update is $48.4 million at the system level.

Q. How does this year's level of EIM benefits compare to prior APCU filings?

A. The level of EIM benefits included in this year's October Update is the highest of any prior APCU filing. It is 39 percent higher than last year's settled benefit amount and 290 percent higher than last year's initially filed benefit amount.[2]

Q. Please describe Idaho Power's methodology for calculating the EIM benefits included in the 2024 October Update.

A. Idaho Power starts with the California Independent System Operator's ("CAISO's") EIM benefit methodology and then includes two adjustments related to hydro pricing. These adjustments are discussed in detail in Idaho Power/100, Brady/26-28. The calculation utilizes the most recently available 12 months of data. The October Update EIM benefits of $48.4 million are therefore based on the actual benefits as determined by CAISO, with these two adjustments, for the 12 months ending August 2023.

Q. Please summarize Staff's proposed adjustment to EIM benefits.

A. Staff is proposing that, beginning in this year's March Forecast, Idaho Power apply a growth factor to its EIM benefit calculation. Staff's calculated growth factor for the 2024 APCU filing (based on CAISO benefit data through Q3 2023) is 61 percent. Staff's growth factor is calculated based on the average year-over-year growth in CAISO-reported EIM benefits for all participants since the inception of the EIM.

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[2] For settlement purposes, the stipulating parties agreed to increase EIM benefits in UE 414 (2023 APCU) by $22.3 million. The stipulating parties did not agree on any methodological change to the EIM benefits calculation.

Based on the level of EIM benefits included in this year's October Update, this would result in an increase to EIM benefits of $29.5 million at the system level, or $1.3 million on an Oregon-allocated basis. Staff proposes that the growth factor should be recalculated for the March forecast based on the CAISO benefit data through Q4 2023.

Q. Does applying the 61 percent growth factor result in a reasonable level of EIM benefits for Idaho Power?

A. No. As the Company previously stated, the current level of benefits included in this year's October Update is already the highest level of benefits of any APCU filing. It is 92 percent higher than the level of benefits included in the 2022 APCU, which was previously the highest level of calculated benefits of any APCU filing.

In addition, after applying the 61 percent growth factor, the level of proposed benefits would be 528 percent higher than last year's calculated benefit amount and 124 percent higher than last year's settled benefit amount.

<u>Table 1: Change in Year Over Year EIM Benefits – Staff's Proposed Amount</u>

Year	EIM Benefits	% Change in Benefits
2023 Calculated (Filed)	$12,421,081.64	
2024 Staff Proposed	$77,983,788.63	528%
2023 Stipulated	$34,739,015.72	
2024 Staff Proposed	$77,983,788.63	124%

Q. How have Idaho Power's calculated EIM benefits changed over time?

A. Table 2 shows the year-over-year changes in Idaho Power's calculated (filed) EIM benefits from 2019 to 2024, which were used as the basis for the APCU filings.

Table 2: Change in EIM Benefits

Year	Idaho Power Calculated EIM Benefits	% Change in Benefits
2019	$15,120,068.29	
2020	$16,886,332.35	12%
2021	$18,941,324.14	12%
2022	$25,235,426.43	33%
2023	$12,421,081.64	-51%
2024	$48,437,135.79	290%

For the 2019 - 2022 APCU filings, EIM benefits were generally increasing. However, for the 2023 APCU filing, calculated EIM benefits decreased by 51 percent. This was largely attributed to the general decrease in the flexibility of the Company's resource stack due to poor hydro conditions, limited coal supply, high natural gas and market prices, and summer transmission constraints.

The increased level of benefits for the 2024 APCU is largely attributable to a one-time issue with pricing used for Bridger in April and May that will not exist into the future due to the conversion of Bridger Units 1 and 2 to natural gas in the first half of 2024.

Q. Do these historical benefit numbers follow a consistent trend?

A. No. Figure 1 below shows the 2019 - 2024 EIM benefits plotted over time. It also includes Staff's proposed level of EIM benefits for 2024 with the 61 percent growth factor included. As demonstrated by the variance in 2023 and 2024 benefits from the best-fit trendline (dotted line), annual changes in EIM benefits have not followed a consistent trend or pattern. Accordingly, there is not enough evidence to conclude that benefits will trend by a certain percentage, or even in a certain direction, in the future. EIM benefits vary based on hydro conditions, market and gas price volatility, and other market conditions. None of these factors trend linearly in one direction over time.

Figure 1: EIM Benefits Over Time

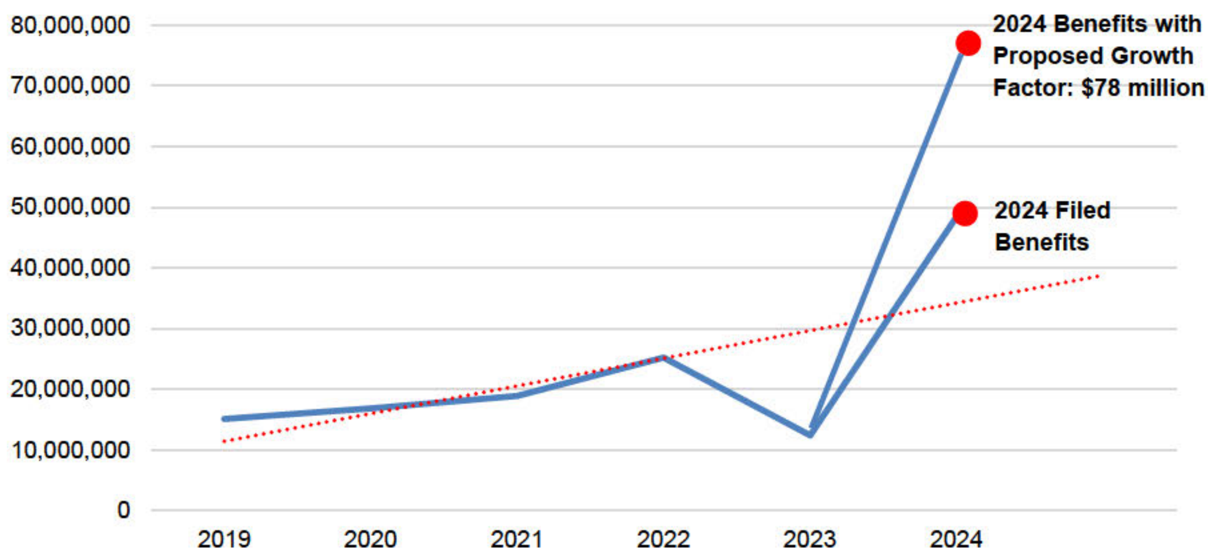
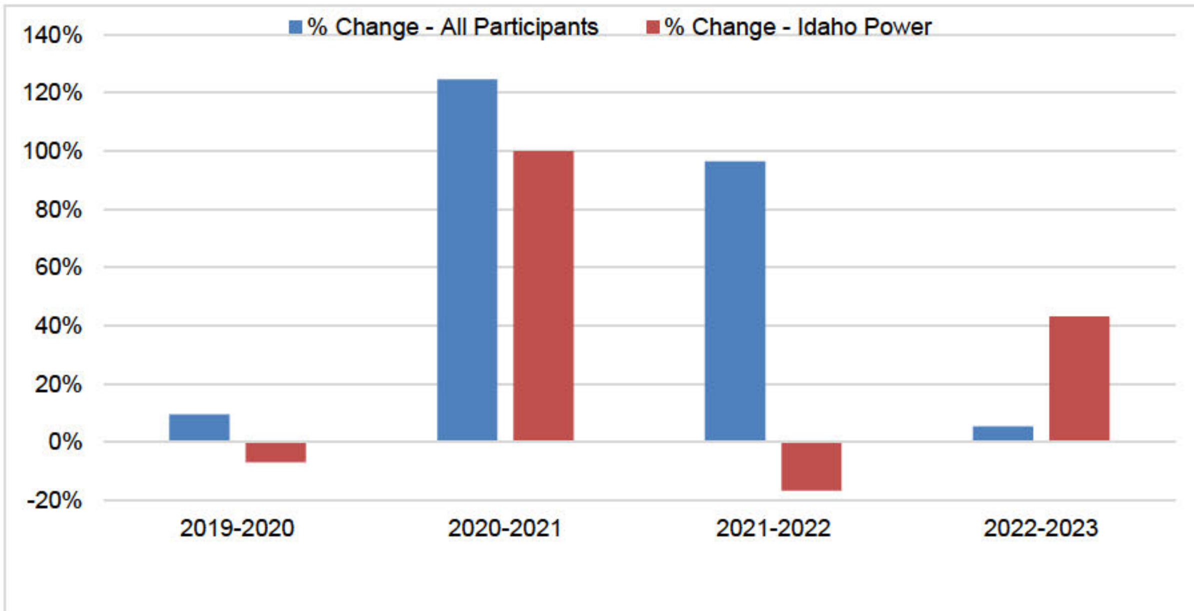


Figure 1 also illustrates the relatively sharp increase (528 percent) between the 2023 benefit amount and the 2024 amount with Staff's proposed growth rate. It also highlights that the Company's filed level of benefits is already a relatively high increase from historical levels.

Q. You previously mentioned that Staff's growth factor is based on the average year-over-year growth for all participants since the inception of the EIM. Are the average historical changes in EIM benefits for all participants correlated to the average changes for just Idaho Power?

A. No. Figure 2 below shows that in two of the four years, Idaho Power's growth rate based on CAISO reported benefits was negative while the total growth rate for all participants was positive. This graph also shows that Idaho Power has never had continual year-over-year increasing EIM benefits.

Figure 2: Year-over-Year % Change in CAISO Reported EIM Benefits (Idaho Power vs All Participants)



Q. What is Staff's rationale for proposing Idaho Power apply a growth factor to its EIM benefits?

A. Generally, Staff argues that EIM benefits have grown annually for participants, and are anticipated to grow in the future. As a result, Staff argues that because the APCU is based on a forward-looking test year, Idaho Power's EIM benefits should incorporate this projected growth as opposed to its current process of utilizing historical benefit data in the test year.[3]

Q. Does Idaho Power agree with Staff's rationale for the proposed adjustment?

A. No. Based on both the CAISO reported benefit numbers and Idaho Power's calculated benefit numbers, it cannot be concluded that Idaho Power's benefits will grow year-

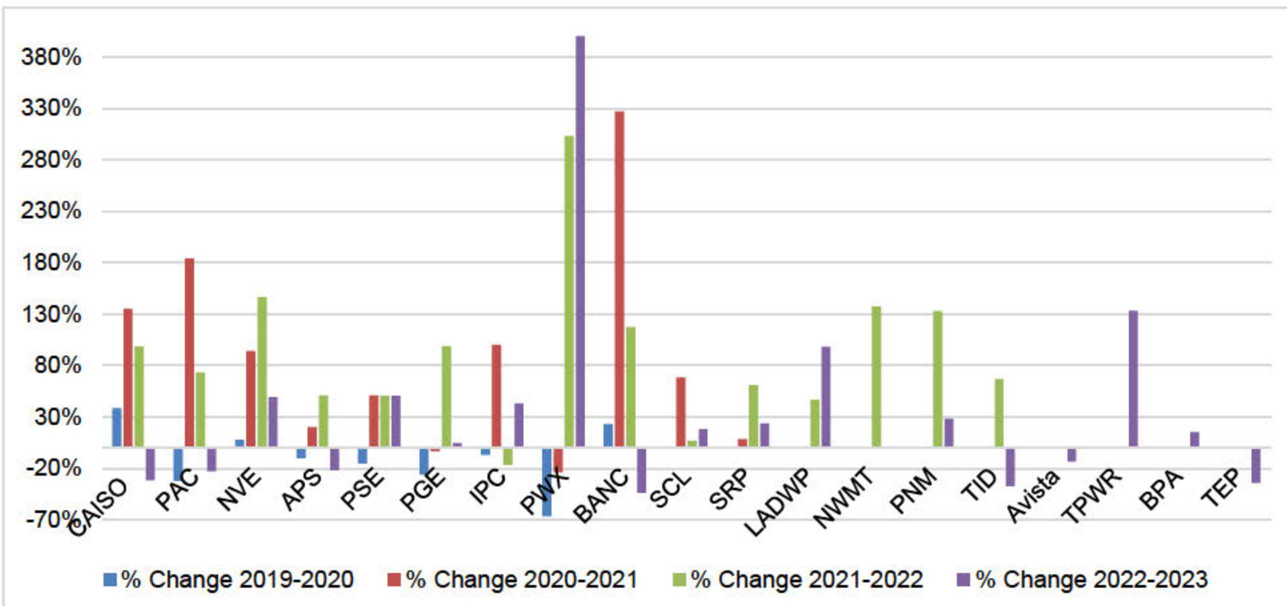
[3] Staff/200, Dyck/7.

over-year. Both sets of data show no statistically significant growth trend in benefits for Idaho Power.

Q. Has Idaho Power reviewed annual growth rates for other EIM participants?

A. Yes. Figure 3 below shows annual percent changes in CAISO benefit numbers for all participants from calendar years 2019 - 2023. Because many participants joined the EIM in Q2 of the respective year, Idaho Power set their level of benefits in Q1 equal to their Q2 benefits for the purpose of this analysis.

Figure 3: Year-over-Year % Change in CAISO Reported EIM Benefits (Individual Participants)



Q. What did the Company conclude from its analysis?

A. Changes in EIM benefits vary by year and participant. An average of volatile growth rates for all years and participants does not provide a good representation for how benefits will change in any given year for a specific participant.

Between 2019 and 2020, 6 participants (67 percent) saw a decrease in benefits while 3 participants (33 percent) saw an increase. In addition, between 2022 and 2023, 8 participants (42 percent) saw a decrease in benefits while 11 participants (58 percent) saw an increase in benefits.

Between 2021 and 2022, Idaho Power saw a decrease in benefits while all other participants saw an increase. During this time, two participants joined the EIM: Bonneville Power Administration and Tucson Electric Power. This does not align with Staff's position that an increase in participants will generally lead to an increase in benefits for Idaho Power.

Q. Please summarize Idaho Power's response to Staff's proposed adjustment to EIM benefits.

A. Based on the Company's analysis of both the CAISO reported and Idaho Power-calculated EIM benefits, there is not enough evidence to conclude that Idaho Power's EIM benefits will trend upwards over time. Staff's methodology of using an average growth rate based on all participants for all years does not consider how an individual participant's benefits have changed over time. The simple averaging of volatile year-over-year percentage changes is not a valid methodology to determine future expectations.

In addition, Staff' proposed growth rate does not result in a reasonable level of benefits for Idaho Power. This year's filed benefit amount of $48.4 million is already approximately 173 percent higher than the historical average. A 61 percent growth rate in addition to the already increased levels included in this year's APCU filing is not realistic.

<u>PURPA Forecast</u>

Q. Please describe the methodology for forecasting PURPA <u>generation</u> for the APCU October Update.

A. Forecast PURPA generation in the APCU is based on a rolling 5-year average of actual generation data and/or a mix of actual generation data and initial project estimates if 5 years of data is not available. In addition, because the October Update establishes a “normal” net power supply expense value, the Company models new qualifying facilities (“QF”) as annualized online resources for the entire test year.

Q. Please describe the methodology for forecasting PURPA <u>expenses</u> for the APCU October Update.

A. Forecast PURPA expenses are calculated by multiplying the forecast generation by the associated monthly price for each QF. This monthly price is either the Oregon reprice rate, or the energy prices within the respective QF contract.

Q. Please describe the Oregon reprice rate.

A. Several of the Company’s PURPA contracts in both Idaho and Oregon have payment provisions that require the Company to provide levelized monthly payments to the QF over the life of the contract.

In Idaho, the levelized payment stream for these contracts is reflected in customer rates for recovery of PURPA expenses. In Oregon, a non-levelized payment stream for these contracts is reflected in customer rates for recovery of PURPA expenses, even though Company’s actual payments to these QFs are levelized over the life of the contract.

The majority of the QFs with which Idaho Power has PURPA agreements are located within the state of Idaho and contain Idaho Commission-approved terms and conditions, including avoided cost values. However, the OPUC has required Idaho Power to reprice the estimated expected energy production from these PURPA projects using Oregon PURPA avoided costs to reflect an estimated cost as if these projects were all subject to Oregon PURPA avoided costs at the time they were executed. The Oregon avoided costs according to Schedule 85, Cogeneration and Small Power Production Standard Contract Rates, at the time a contract was executed, is known as the Oregon reprice rate.

For all levelized contracts and Idaho non-levelized contracts executed before 2003, the Oregon reprice rates are used for forecasting expenses in the APCU. For all Idaho non-levelized contracts executed after 2003 and all Oregon contracts that are not repriced based on the above, the rates used for APCU forecasting are the energy prices within the respective contract.

Q. What is the impact of using Oregon reprice rates for forecasting PURPA expenses?

A. By using non-levelized avoided cost rates for PURPA cost recovery, the Company under-collects PURPA expenses in the early years and over-collects PURPA expenses in the later years for the repriced projects. Over the life of the contract term, the present value of the payments is the same whether they're collected through a levelized payment stream or non-levelized payment stream. Because the majority of the repriced contracts are in the last few years of their term, it is expected that the repriced PURPA forecast expenses will be greater than actual expenses.

Q. Please describe the history of the Oregon repricing process, including any past discussions regarding the process with the OPUC.

A. Starting with the 1983 Year End Report of Operations to the OPUC, the Company complied with a request from Oregon to use Oregon specific avoided cost rates for the levelized rate contracts.

In the Company's 2013 APCU filing, Staff conducted extensive discovery regarding PURPA repricing. In response to Staff's Data Request No. 25 in that case, Idaho Power provided a list of historical filings, data requests, and reports that the Company made where the repricing methodology was stated and accepted. This was also provided in response to Staff's Data Request No. 78 of this year's case, and has also been included with my Reply Testimony as Exhibit 201.

In addition, after several rounds of workshops regarding the regulatory treatment of PURPA expenses in Oregon, parties agreed in the 2013 APCU that Idaho Power's existing and past practice of repricing PURPA contracts executed in Idaho to reflect Oregon's non-levelized methodology is reasonable, as reflected in the Partial Stipulation filed in that case:

> *For purposes of this Partial Stipulation, the Stipulating Parties agree that Idaho Power's method of repricing PURPA contracts executed in Idaho to reflect Oregon's non-levelized methodology is reasonable.*[4]

Q. Has the Company historically under-collected PURPA expenses in rates due to repricing?

A. Yes. The settlement stipulation in the Company's 1995 General Rate Case filing[5] shows the $382,000 decrease to the Oregon jurisdictional revenue requirement associated with PURPA repricing. See Exhibit 202. According to Staff's Issue Summary provided to the Company in that docket (see Exhibit 203), the system level PURPA forecast in that case based on Idaho contract values was $34.1 million, while the forecast based on Oregon avoided cost rates was $24.1 million, a difference of $10 million on a system basis.

The Company's next general rate case was not until 2005, where Order No. 05-871 directed parties to develop a new mechanism for power cost recovery. In 2007, parties established the first APCU filing.

Q. Please describe how Staff calculated the proposed $36.1 million, or 14.3 percent, adjustment to PURPA expenses.

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[4] *In the Matter of Idaho Power Company 2013 Annual Power Cost Update*, Docket No. UE 257, Order No. 13-166 (May. 6, 2013).

[5] Docket No. UE 92.

A. Staff calculated the average percent variance between the total forecast *expenses* and actual *expenses* for the 2020, 2021, and 2022 APCU filings. Staff's calculation, as shown in Table 1 of Staff's testimony,[6] is calculated with the data provided in the Company's response to Staff's Data Request No. 56.

Q. What is the corresponding variance between forecast and actual PURPA generation according to this dataset and time period?

A. For the same time period, the calculated average percent variance in *generation* between forecast and actuals is 2 percent. In other words, the Company's forecast of QF *generation* is accurate and therefore the difference in QF *expense* is attributable to the price applied to the generation.

Q. Please describe the dataset provided in Idaho Power's response to Staff's Data Request No. 56.

A. The dataset includes forecast and actual PURPA generation and expenses by project for the 2018 – 2023 APCU test years.[7] The forecast generation and expenses are from the March Forecast of each APCU filing.

Q. Does the Company agree with the calculation Staff used to arrive at the proposed 14.3 percent adjustment to PURPA expenses?

A. No. Comparing the forecast PURPA expenses to actual expenses using the dataset provided in the Company's response to Staff's Data Request No. 56 will not provide an indication of the accuracy of the Company's October Update PURPA forecast.

The forecast expenses in this dataset are calculated with the Oregon reprice rate for the applicable QFs, while the actual expenses represent what was actually paid to QFs in that time period. As a result, there will be a known variance between forecast and actual expenses due to the repricing process.

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[6] Staff/300, Ratliff/3.

[7] Actual generation and expenses are not yet available for the 2023 APCU test year.

Q. Does Staff recommend eliminating the repricing methodology?

A. No. Staff "recommends the continued use of the Oregon repricing method for forecasting PURPA expenses reduced by 14.3 percent to align the forecasts with the historical actual expenses."[8] Recommending the continued use of Oregon repricing but also recommending an adjustment to align the forecast to actuals is contradictory. The repricing methodology results in an <u>expected</u> difference between forecast and actuals based on the nature of the non-levelized versus levelized payment streams.

Confidential Exhibit 204 contains a record from March 5, 1987, that helps illustrate the expected difference between the repriced forecast and actual expenses. It contains the projected annual payment stream for Faulkner Ranch under both the levelized contract rates and non-levelized Oregon repriced rates. It shows that in Faulkner Ranch's final contract year of 2021, payments based on contract rates were expected to be less than Oregon repriced payments by 45 percent. The Company's response to Staff's Data Request No. 56 shows that in the 2021 APCU test year, actual expenses for Faulkner Ranch were 41 percent less than forecast expenses, aligning with expectations that existed when the Oregon repricing methodology was initially set.

The same 1987 payment stream shows that in 1995, expenses based on contract rates were projected to be 204 percent higher than Oregon repriced expenses.

Q. Please summarize Idaho Power's response to Staff's proposed adjustment to PURPA expenses.

[8] Staff/300, Ratliff/5.

A. Staff's proposal states that the Company should continue its repricing of forecast PURPA expenses, but that it should also decrease its forecast to more closely align with historical actuals. The proposal is contradictory based on the nature of the repricing process. Repricing creates an expected difference between forecast and actual expenses. As most of these projects are in the later years of their contracts, it is expected that the repriced forecast will be higher than actuals.

In addition, to address Staff's concern that the Company "…has not substantiated the alleged reason for the over forecast with evidence showing the earlier under recovery of PURPA costs…"[9], Idaho Power has provided evidence that the Company historically under-collected PURPA expenses in rates in its 1995 general rate case. It has also provided historical Oregon repriced PURPA forecasts from 1987 to support the Company's statement that the Oregon repriced expenses were less than actual expenses in the early years of the contracts.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

[9] Staff/300, Ratliff/4.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 201
Docket No. UE 257 – Idaho Power Company's Response to Staff's Data Request 25
Historical Evidence of Repricing

February 28, 2024

IDAHO POWER®
An IDACORP Company

January 10, 2013

Subject: Docket No. UE 257
Idaho Power Company's Responses to Staff's Data Request 25

PURPA QUALIFIED FACILITIES

STAFF'S DATA REQUEST NO. 25:

Regarding Idaho Power's response to Staff Data Request 15, part "e," where the Company represented:

> ***"The majority of the Idaho Power PURPA agreements are located within the state of Idaho and contain Idaho Commission-approved terms and conditions, including avoided cost values. The Oregon Commission has required Idaho Power to reprice the estimated expected energy production from these PURPA projects using Oregon PURPA avoided costs [emphasis added] to reflect an estimated cost as if these projects were all subject to Oregon PURPA avoided costs at the time they were executed."***

Please identify and provide a copy of the orders (including docket numbers) where the Oregon Commission has required Idaho Power to reprice the estimated expected energy production from Idaho Power's PURPA facilities located in the state of Idaho using Oregon PURPA avoided costs. Please indicate the specific page(s) of such orders.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 25:

The repricing for the Public Utility Regulatory Policies Act of 1978 ("PURPA") contracts has spanned a time period of nearly 30 years. When PURPA contracts with Idaho Power Company ("Idaho Power" or "Company") were first established in the early 1980s, Idaho regulation required PURPA contracts to be priced using a levelized pricing methodology. Practices in Oregon, however, required the Company to reprice the Idaho PURPA contracts as if those contracts had been signed in Oregon. The practice in Oregon required PURPA contracts to be priced using a non-levelized methodology. In the early years, the non-levelized rates were lower than the levelized rates; however, later in the contract life, there is a cross-over where the non-levelized rates become higher than the levelized rates. While the Company is not aware of a specific Public Utility Commission of Oregon ("OPUC" or "Commission") order directing the Company to perform the repricing of PURPA contracts, it has long been understood that the levelized methodology used in Idaho was not allowed for use in Oregon. Evidence of this practice and acceptance by the OPUC is found in a long list of filings, data requests, and reports that the Company has made where this repricing methodology was stated and accepted. In addition to this current Annual Power Cost Update ("APCU"), Docket UE 257, Idaho Power has repriced PURPA in each of the previous three APCU filings (Docket Nos. UE 214, UE 222, and UE 242) and the Commission ultimately approved the resulting PURPA costs in each case.

Starting with the 1983 Year-End Report of Operations to the OPUC, the Company complied with Oregon's request of using Oregon-specific avoided cost rates. Below are numerous examples that span the nearly 30 years of PURPA repricing. In addition, below is specific language contained in Staff or Company statements.

1. On May 10, 1984, the correspondence accompanying the 1983 Year-End Report of Operations for the twelve months ending December 31, 1983, the Company states: "We have calculated annualized CS&PP purchased power costs for the twelve months ended December 31, 1983 at the approved Oregon avoided costs. If you require the costs based on Idaho Rates, please let me know and we will prepare that data for you."

   On October 26, 1984, the correspondence accompanying the Mid-Year Report of Operations for the twelve months ending June 30, 1984, the Company states: "Annualized CSPP purchases in the amount of $6,509,600 have been calculated for the twelve months ended June 30, 1984 at the then approved Oregon avoided costs. The same calculation using Idaho avoided costs would result in CSPP purchases in the amount of $9,869,900."

   On May 9, 1985, the correspondence accompanying the Year-End Report of Operations for the twelve months ending December 31, 1984, the Company states: "Annualized CSPP purchases in the amount of $9,022,100 have been calculated for the twelve months ended December 31, 1984 at the then approved Oregon avoided costs. The same calculation using Idaho avoided costs would result in CSPP purchases in the amount of $12,636,000."

   On May 29, 1986, the correspondence accompanying the Year-End Report of Operations for the twelve months ended December 31, 1985, the Company states: "Annualized CSPP purchases in the amount of $11,331,100 have been calculated for the twelve months ended December 31, 1985 at the then approved Oregon avoided costs. The same calculation using Idaho avoided costs would result in CSPP purchases in the amount of $19,540,800."

   On May 7, 1987, the correspondence accompanying the Year-End Report of Operations for the twelve months ended December 31, 1986, the Company states: "Annualized CSPP purchases in the amount of $15,107,600 have been calculated for the twelve months ended December 31, 1986 at the then approved Oregon avoided costs. The same calculation using Idaho avoided costs would result in CSPP purchases in the amount of $26,247,600."

   On April 15, 1988, the correspondence accompanying the Year-End Report of Operations for the twelve months ended December 31, 1987, the Company states: "Annualized CSPP purchases in the amount of $20,186,800 have been calculated for the twelve months ended December 31, 1987 at the then approved Oregon avoided costs. The same calculation using Idaho avoided costs would result in CSPP purchases in the amount of $25,964,700."

On April 27, 1989, the correspondence accompanying the Year-End Report of Operations for the twelve months ended December 31, 1988, the Company states: "Annualized CSPP purchases in the amount of $22,369,800 have been calculated for the twelve months ended December 31, 1988 at the then approved Oregon avoided costs. The same calculation using Idaho avoided costs would result in CSPP purchases in the amount of $31,230,300."

On May 17, 1990, the correspondence accompanying the Year-End Report of Operations for the twelve months ended December 31, 1989, the Company states: "Annualized CSPP purchases in the amount of $24,507,600 have been calculated for the twelve months ended December 31, 1989 at the then approved Oregon avoided costs. The same calculation using Idaho avoided costs would result in CSPP purchases in the amount of $33,719,100."

Similar repricing occurred in each of the subsequent Year-End Report of Operations, including the Company's most recent Year-End Report of Operations for the twelve months ended December 31, 2011, submitted on April 16, 2012. In that Report, the Company showed an Idaho co-generation and small power production amount of $113,525,417 compared to the Oregon repriced amount of $133,351,508.

All of the correspondence listed above is included as Attachment 1.

2. On August 15, 1995, the Company responded to Data Request No. 25 in Docket UE 92, First Discovery Request of Low Income Consumers Union and Wilma and Ernest Apodaca, please see Attachment 2. The request and response are stated below.

   Q. "Explain how and why IPC repriced QF purchases based upon Oregon QF rates."

   A. "The Company repriced actual QF purchases by using avoided costs approved by the Oregon Public Utility Commission and applied the costs to all of the Company's QF contracts, including QF contracts subject to Idaho avoided cost rates. Avoided costs for each project reflect actual historical avoided costs at the time individual contracts were signed. The Company repriced the QF contracts for purposes of inclusion in the semi-annual reports at the request of the Oregon PUC Staff."

3. On September 1, 1995, a settlement proposal in Docket UE 92 that was sent from the OPUC Staff addresses Staff's proposed adjustment to the Company's filing. As stated on Attachment 3, "Company filed QF costs are based on Idaho Commission avoided cost rates. However, staff's adjusted QF costs of $3.6 million for all QF contracts and $20.5 million for third party QF contracts are based on Oregon Commission avoided cost rates."

4. On January 20, 2010, in Docket UE 214, OPUC Staff witness Ed Durrenberger agrees with the Company's repricing methodology. He stated, "The Company has repriced some of its existing PURPA qualifying facility (QF) contracts to reflect a Commission

requirement that actual PURPA power costs be reflected in rates rather than levelized power costs . . . . I agree with the Company's second point, that the Commission has required a non-levelized pricing methodology." A copy of a portion of Mr. Durrenberger's Opening Testimony in Docket UE 214 is provided as Attachment 4.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 202
Docket No. UE 92 – Settlement Stipulation

February 28, 2024

ORDER NO. 95-1240

ENTERED NOV 2 8 1995

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 92
UI 110

In the Matter of the Application of IDAHO POWER COMPANY for Authority to Increase its Rates and Charges for Electric Service to Customers in the State of Oregon. UE 92.	)	ORDER
In the Matter of the Application of IDAHO POWER COMPANY for an Order Approving Firm Energy Sales Agreements. UI 110.	)	

DISPOSITION: RATE CHANGES AUTHORIZED; STIPULATION ADOPTED; PROCEEDING BIFURCATED; ENERGY AGREEMENTS APPROVED

UE 92

On May 10, 1995, Idaho Power Company (IPCO) filed revised tariff schedules designed to increase rates to Oregon retail electric customers by approximately $3.37 million per year. The schedules were accompanied by testimony supporting the rate increase request. The proposed increase varies among customer groups, but totals 16.7 percent overall. The tariff schedules were scheduled to become effective on June 10, 1995. At its June 6, 1995, public meeting, the Commission suspended the schedules for a period of time not to exceed six months from June 10. The Commission memorialized its decision in Order No. 95-563.

During May 1995, IPCO gave notice of its filing by purchasing display space in newspapers in Ontario, Baker City, Vale, and Halfway, Oregon.

The Commission held a prehearing conference on June 26, 1995, in Salem, and a hearing in Ontario on August 3, 1995.

The parties to this proceeding are IPCO, the Commission's staff, Industrial Customers of Idaho Power of Oregon (ICIP), Citizens' Utility Board (CUB), Low Income Consumers Union and Wilma and Ernest Apodaca (together referred to as LICU), and Charles L. Best.

On September 25, 1995, LICU filed testimony recommending that the Commission order IPCO to spend a portion of any rate increase on a program of weatherization proposed by LICU. During September, settlement conferences were held. On October 18, 1995, IPCO, staff, ICIP, and CUB filed a settlement stipulation in which they recommend that the Commission approve their agreement as to revenue requirement and rate structure issues. Staff filed testimony in support of the stipulation. No objection to the stipulation has been filed.

On October 26, 1995, Administrative Law Judge Lowell Bergen issued a ruling bifurcating the proceeding, putting the issues addressed in the stipulation in Phase I and the issue raised by LICU in Phase II.

Included in the stipulation are the following agreements:

1. IPCO should be allowed to increase its rates to recover an additional $1,329,000 per year more than its 1993 base revenue levels. The increase amount is 6.57 percent of 1993 Oregon revenues. IPCO does not agree with the adjustments used to reach that revenue increase amount, but agrees to accept authorization for that increase;

2. The rate increase should be designed and spread among the customer classes according to an addendum to the stipulation. The addendum lists the increase to IPCO's three largest customer groups as follows: 5.53 percent for residential service, 11.06 percent for small general service, and 16.59 percent for irrigation service;

3. Contracts between IPCO and the operators of five qualifying hydroelectric generating facilities should be approved.

Staff made numerous adjustments to IPCO's ratebase, expense, and revenue requirement numbers in developing its position about the requested rate increase. IPCO does not agree with those adjustments, although it is willing to accept staff's position to resolve the case. The Commission has reviewed the adjustments and finds the evidence supporting them to be persuasive.

The stipulated revenue requirement incorporates a rate of return of 8.95 percent, comprised of the following components: long-term debt cost of 8.02 percent; preferred stock cost of 5.9 percent; and, common equity cost of 10.5 percent. The common equity cost is within a range of reasonableness computed according to the capital asset pricing model and the discounted cash flow model. The parties do not agree on the best way to compute the cost of common equity, but agree that the stipulated cost is reasonable. The Commission has reviewed the stipulated cost of capital and finds it to be reasonable.

The stipulated rate structure is based on IPCO's marginal cost study, as revised by staff. The stipulated rate spread moves the various customer classes closer to recovering an equal share of the marginal cost of service for each class.

The settlement stipulation includes a moratorium on termination of service for non-payment of bills during the months of December, January, and February. That is, service could not be terminated during those months for an unpaid service bill. The customer would be offered a time payment plan, but termination of service could not occur until March 1 if no payment plan was executed. The plan is designed to combat the cold winter climate in IPCO's Oregon service territory and duplicates a policy in effect in Idaho. The plan would apply to customers who declare they cannot pay their bills and whose household includes children, elderly, or infirm persons. If approved, the plan would be in effect for one year, at which time IPCO would review how well it has worked.

The Commission notes that the proposed termination plan is a departure from existing Commission rules regarding termination of service for nonpayment. The plan allows a customer to self-certify eligibility, and does not require the execution of a time-payment plan. However, the Commission will approve the stipulated plan to see how it works. The Commission's approval is limited to the specific situation prevailing in this proceeding.

IPCO has demonstrated a need for additional revenues from Oregon operations in the amount of $1,329,000 per year. It should be allowed to change its tariff schedules to increase revenues by that amount. The Commission has considered the stipulation and finds the agreements in it to be reasonable. Rates developed in accordance with this order will be fair, just, and reasonable.

UI 110

On March 21, 1991, IPCO filed an application requesting approval of firm energy sales contracts with affiliated interests for two hydroelectric facilities. The application was later amended to include three additional hydroelectric facilities. The facilities are partially owned by subsidiaries of Ida-West Energy Company, a wholly-owned subsidiary of IPCO. The agreements cover these projects: Hazelton B; Wilson Lake Hydro; Marysville Hydro; Y-8 Hydro; and South Forks (lowline). IPCO on several occasions requested that the Commission delay consideration of its application, and the application was ultimately consolidated with Docket No. UE 92.

There is no objection to Commission approval of the contracts involving the five hydroelectric facilities. The Commission is approving them in this order, and adopts for purposes of setting rates in this proceeding the results reflected in the stipulation.

ORDER

IT IS ORDERED that:

1. The revised tariff schedules filed by IPCO on May 10, 1995, are permanently suspended;

2. IPCO is authorized to file revised tariff schedules to increase its annual revenues from Oregon electric operations by $1,329,000. The revised tariff schedules must conform to the terms of the stipulation and this order. The revised tariff schedules may become effective two working days after they are filed;

3. The stipulation attached as Appendix A to this order is adopted;

4. This proceeding is bifurcated. The issues addressed in the stipulation are included in Phase I, and the issue raised by LICU is assigned to Phase II;

5. Concerning the affiliated interest transactions filed in Docket No. 110:

   a. IPCO shall provide the Commission access to all books of account as well as all documents, data, and records of IPCO and IPCO's affiliated interests which pertain to transactions between IPCO and the subsidiaries of Ida-West Energy Company;

   b. IPCO shall notify the Commission in advance of any substantive changes to the agreements, including any material changes in cost. Any changes to the agreements' terms which alter the intent or extent of activities under the agreements from those approved in this order shall be submitted for approval in an application for a supplemental order, or other appropriate format in this docket;

ORDER NO. **95-1240**

c. For accounting purposes, IPCO shall record in its regulated books of account the purchased power costs, appropriately allocated to Oregon customers, based on the Commission's approved avoided cost rates;

Made, entered, and effective NOV 28 1995.

Roger Hamilton
Chairman

Ron Eachus
Commissioner

COMMISSIONER SMITH WAS UNAVAILABLE FOR SIGNATURE

Joan H. Smith
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR
860-14-095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-13-070(2)(a). A party may appeal this order to a court pursuant to ORS 756.580.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 92

In the Matter of the Application of IDAHO POWER COMPANY for Authority to Increase its Rates and Charges for Electric Service to Customers in the State of Oregon.	))))))	SETTLEMENT STIPULATION

Pursuant to the settlement conferences on Monday, September 11, 1995 and Wednesday, September 13, 1995, Idaho Power Company, (hereinafter "Idaho Power"), the Public Utility Commission of Oregon's Staff (hereinafter "Staff"), the Idaho Power Oregon Industrial Customers (hereinafter "Industrial Customers"), and the Citizens Utility Board of Oregon (hereinafter "CUB"), all of which are parties of record in this proceeding, submit the following settlement stipulation.

INTRODUCTION

On May 10, 1995, Idaho Power filed an application with the Commission for general rate relief. The case was docketed as UE 92. Accompanying the application were testimony and exhibits supporting the application. As a result of settlement conferences held on Monday, September 11, 1995 in Salem, Oregon, and Wednesday, September 13, 1995 by teleconference, the above-referenced parties have agreed on an amount of an additional revenue requirement to be recovered by Idaho Power. In conformance with those settlement discussions, the parties hereby submit this settlement stipulation to the Commission and request that the Commission accept and approve the settlement as presented.

AGREEMENTS

(1) Idaho Power will increase its rates to recover an additional $1,329,000 over and above the 1993 base revenue levels identified in the Company's testimony and exhibits accompanying its application.

(2) Idaho Power should not be required to recalculate the carrying charge on the deferred amounts associated with UE 91. The carrying charge associated with UE 91 deferrals should change prospectively at the time the UE 92 rates are implemented. The parties agree to support an Idaho Power request for an amended order in Docket UE 91 to make the interest rate change prospective.

(3) Idaho Power will cease Ballot Measure 5 accruals at the time the UE 92 rates are implemented.

(4) The spread and design of the rates to recover the increased revenue requirement will be in accordance with an Addendum No. 1 which is attached to this settlement stipulation.

(5) In Docket No. UI 110, Idaho Power had requested Commission approval of five contracts between Idaho Power and the developers of qualifying small hydroelectric generating facilities. An affiliate of Idaho Power owns a minority interest in the qualifying small hydroelectric

facilities. As a part of this settlement stipulation, the parties have agreed that the five contracts should be approved by the Commission. On September 20, 1995, Staff filed a motion to consolidate Docket No. UI 110 with Docket No. UE 92.

(6) Staff's proposed adjustments to Idaho Power's revenue requirement filing in this case and in UI 110 are set out in Addendum No. 2 which is attached to this settlement stipulation. Idaho Power does not agree with the adjustments proposed by Staff, but Idaho Power has agreed to accept the additional revenue requirement of $1,329,000 which is reflected in that attachment. Staff will file testimony and exhibits in support of this settlement stipulation.

(7) By entering into this settlement stipulation, no party shall be deemed to have approved, accepted or consented to the facts, principles, methods or theories employed by any other party in arriving at the agreed upon revenue requirement specified in paragraph 1.

(8) The parties agree that this stipulation will be submitted to the Commission for acceptance, and the parties recommend that the Commission issue an order in this docket (and in Docket UI 110 if Staff's motion to consolidate described in paragraph 5 is denied) adopting this settlement stipulation. If this stipulation is not accepted in its entirety, it will be withdrawn and shall be without any force or effect.

(9) The parties to this agreement have agreed that they would urge that rates be effective as soon as reasonably possible.

95-1240

This settlement stipulation may be executed in counterparts.

PUBLIC UTILITY COMMISSION OF OREGON

By: Michael T. Weirich
Mike Weirich
Assistant Attorney General
Dated: 10/16/95

IDAHO POWER COMPANY

By: Gene C. Rose
Gene C. Rose, Attorney
Dated: 10/13/95

IDAHO POWER OREGON INDUSTRIAL CUSTOMERS

By: Peter J. Richardson
Peter Richardson, Attorney
Dated: October 12, 1995

CITIZENS UTILITY BOARD OF OREGON

By:
Jason Eisdorfer, Attorney
Dated:

This settlement stipulation may be executed in counterparts.

PUBLIC UTILITY COMMISSION OF OREGON

By: Michael T. [signature]
Mike Weirich
Assistant Attorney General
Dated: 10/16/95

IDAHO POWER COMPANY

By: Gene C Rose
Gene C. Rose, Attorney
Dated: 10/13/95

IDAHO POWER OREGON INDUSTRIAL CUSTOMERS

By: Peter J. Richardson
Peter Richardson, Attorney
Dated: October 12, 1995

CITIZENS UTILITY BOARD OF OREGON

By: ____________________
Jason Eisdorfer, Attorney
Dated: ____________________

This settlement stipulation may be executed in counterparts.

PUBLIC UTILITY COMMISSION OF OREGON

By: Michael T. W[illegible]
Mike Weirich
Assistant Attorney General
Dated: 10/16/95

IDAHO POWER COMPANY

By: Gene C. Rose
Gene C. Rose, Attorney
Dated: 10/13/95

IDAHO POWER OREGON INDUSTRIAL CUSTOMERS

By:________________________
Peter Richardson, Attorney
Dated:________________________

CITIZENS UTILITY BOARD OF OREGON

By: Jason Eisdorfer
Jason Eisdorfer, Attorney
Dated: October 10, 1995

This settlement stipulation may be executed in counterparts.

PUBLIC UTILITY COMMISSION OF OREGON

By: Michael T. W

Mike Weirich
Assistant Attorney General

Dated: 10/16/95

IDAHO POWER COMPANY

By: Gene C Rose

Gene C. Rose, Attorney

Dated: 10/13/95

IDAHO POWER OREGON INDUSTRIAL CUSTOMERS

By:____________________

Peter Richardson, Attorney

Dated:____________________

CITIZENS UTILITY BOARD OF OREGON

By: Jason Eisdorfer

Jason Eisdorfer, Attorney

Dated: October 10, 1995

REVENUE INDEX TABLES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 1993
OREGON RETAIL JURISDICTION

	Loads (a)	Marginal Costs (b)	Marginal mills/kWh (c)	Current Revenues (d)	Current mills/kWh (e)	% of Marg Cost (f)=(e)/(c)	Indexed (1) % of MC (g)	Proposed Revenues (h)	Proposed mills/kWh (i)	% of Marg Cost (j)=(i)/(c)	Indexed (1) % of MC (k)
R1-Residential	181,569	11,789,126	64.93	8,269,509	45.54	70.1%	99.20%	8,726,720	48.06	74.02%	98.16%
R7 - Sm General Serv	15,543	925,177	59.52	767,527	49.38	83.0%	117.32%	852,391	54.84	92.13%	122.17%
From R8	15,323		59.73	754,770	49.26	82.5%	116.62%	840,379	54.84	91.82%	121.75%
From R33	220		45.02	12,757	58.05	128.9%	182.33%	12,012	54.65	121.39%	160.96%
R9 - Lg Commercial	113,901	6,619,528	58.12	4,734,689	41.57	71.5%	101.15%	5,134,969	45.08	77.57%	102.86%
R9S - From R8	101,861		59.73	4,312,267	42.33	70.9%	100.23%	4,683,339	45.98	76.97%	102.07%
R9S - From R33	3,815		45.02	165,298	43.33	96.2%	136.10%	181,546	47.59	105.69%	140.15%
R9P - From R19	8,225		44.17	257,124	31.26	70.8%	100.09%	270,084	32.84	74.34%	98.58%
R19 - Uniform Contract	143,014	5,293,375	37.01	4,177,590	29.21	78.9%	111.61%	4,227,314	29.56	79.86%	105.90%
R19P-Industrial(P)	86,539		40.60	2,603,730	30.09	74.1%	104.80%	2,658,118	30.72	75.65%	100.32%
R19T-Industrial(T)	56,475		31.51	1,573,860	27.87	88.4%	125.06%	1,569,196	27.79	88.17%	116.91%
R24-Irrigation	58,700	3,626,392	61.78	2,028,746	34.56	55.9%	79.12%	2,365,225	40.29	65.22%	86.49%
R40 - Unmetered (R8)	98		59.73	4,515	46.14	77.2%	109.24%	5,010	51.20	85.72%	113.66%
TOTAL - Without Lighting Tariffs	512,825	28,259,443	55.11	19,982,576	38.97	70.7%	100.00%	21,311,629	41.56	75.41%	100.00%
R15-Dusk To Dawn	417			115,400	276.60			115,400	276.60		
R41-Municipal Ltng	843			122,511	145.43			122,511	145.43		
R42-Signal Lighting	193			7,017	36.35			7,017	36.35		
GRAND TOTAL	514,278			20,227,504	39.33			21,556,557	41.92		

(1) To index, each class's percent of marginal costs was multipled by the ratio of total marginal costs to total present/proposed revenue

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APPENDIX A
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Addendum 1
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IDAHO POWER COMPANY

SUMMARY OF CHARGES AND BASIS FOR RATES

(Reflects Base Rates Excluding Surcharge)

		Secondary		Primary		Transmission	
	Charge	Rate	Basis	Rate	Basis	Rate	Basis
Schedule 1	Customer	4.00	No Change				
	Energy						
	First 300 kWh	0.037588	80% of Other kWh				
	Additional kWh	0.046986	Residual				
Schedule 7	Customer	5.00	Single Phase (N/C)				
		10.00	Three Phase (N/C)				
	Energy	0.047317	Residual				
Schedule 9	Customer	5.00	Single Phase (N/C)				
		10.00	Three Phase (N/C)	85.00	R19P	85.00	R19T
	Basic	0.36	Equal to COS (ID)	0.76	R19P	0.39	R19T
	Demand	3.81	R19S	3.71	R19P	3.59	R19T
	Energy	0.030808	Residual	0.021064	R19P + 2.5% (ID)	0.020595	R9P - losses (ID)
Schedule 19	Customer	10.00	R9S	85.00	30% of COS (ID)	85.00	R19P
	Basic	0.36	R9S	0.76	Equal to COS (ID)	0.39	Equal to COS (ID)
	Demand	3.81	R19P + losses (ID)	3.71	Settlement	3.59	R19P - losses (ID)
	Energy	0.030056	R09S - 2.44% (ID)	0.020550	No Change	0.020092	R19P - losses (ID)
Schedule 24	Customer	10.00	15% of COS (ID)		n/a	85.00	R19T
	Demand (In-Season)	4.34	Settlement		n/a	4.10	R24S - losses (ID)
	Energy (In-Season)	0.028305	Residual		n/a	0.026900	R24S - losses (ID)
	Energy (Out-Season)	0.036031	Seasonal Ratio (ID)		n/a	0.034246	R24S - losses (ID)
Schedule 40	Energy	0.0512	Residual				

Note: Lighting Schedules 15, 41 and 42 are unchanged from current rates.

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Addendum 1
Page 2 of 3

Idaho Power Company

Before the Public Utility Commission of Oregon
Summary of Revenue Impact
State of Oregon
Proformed Normalized 1993 Data

Line No	Tariff Description	(1) Rate Schedule No	(2) 1993 Avg. Number of Customers	(3) 1993 Sales Normalized (KWH)	(4) 1993 Normalized Revenue	(5) Revenue Deficiency	(6) Proposed Revenue (Col. 4+5)	(7) Mills Per KWH	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	11,993	181,569,418	$8,269,509	457,211	$8,726,720	48.06	5.53%
2	Small General Service	7	1,932	15,542,729	767,527	84,864	852,391	54.84	11.06%
2	General Service	9	753	113,901,493	4,734,689	400,280	5,134,969	45.08	8.45%
3	Dusk to Dawn Lighting	15	-	417,209	115,400	0	115,400	276.60	0.00%
4	Uniform Contracts	19	6	143,013,755	4,177,590	49,724	4,227,314	29.56	1.19%
5	Irrigation Service	24	1,195	58,699,832	2,028,746	336,479	2,365,225	40.29	16.59%
6	Unmetered Service	40	7	97,850	4,515	495	5,010	51.20	10.96%
7	Municipal St. Lighting	41	9	842,434	122,511	0	122,511	145.43	0.00%
8	Traffic Control Light.	42	8	193,056	7,017	0	7,017	36.35	0.00%
9	Total Uniform Tariffs		15,903	514,277,776	$20,227,504	$1,329,053	$21,556,557	41.92	6.57%

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IDAHO POWER COMPANY
Summary of Proposed Adjusted Oregon Results
UE-92 Test Year Based on 1993
(000)
Staff Recommendation

		1993 Adjusted Results Per Company (1)	Staff Adjustments (2)	1993 Staff Adjusted (3)	Required Change for Staff Proposed Return (4)	Results at Staff Proposed Return (5)
1	Operating Revenues					
2	Sales to Consumers	$20,227	$0	$20,227	$1,329	$21,556
3	Other Revenues	1,763	(2)	1,761	0	1,761
4	**Total Operating Revenues**	$21,990	($2)	$21,988	$1,329	$23,317
5	Operating Expenses and Taxes					
6	Operation & Maintenance					
7	Net Variable Power Costs	$2,900	($638)	$2,262	$0	$2,262
8	Fixed Power Costs	3,326	0	3,326	0	3,326
9	Other Oper.& Maint.	5,807	(202)	5,605	5	5,610
10	**Total Operation & Maintenance**	$12,033	($840)	$11,193	$5	$11,198
11	Depreciation & Amortization	3,025	(140)	2,885	0	2,885
12	Taxes Other than Income	1,380	(141)	1,239	19	1,258
13	Income Taxes	1,504	219	1,723	510	2,233
14	IERCO Operating Income	(243)	243	0	0	0
15	**Total Operating Expenses and Taxes**	$17,699	($660)	$17,039	$534	$17,573
16	**Utility Operating Income**	$4,291	$658	$4,949	$795	$5,744
17	Average Rate Base					
18	Utility Plant in Service	$105,567	($2,104)	$103,463	$0	$103,463
19	Accumulated Depreciation	(33,349)	52	(33,297)	0	(33,297)
20	Accumulated Deferred Income Taxes	(9,766)	155	(9,611)	0	(9,611)
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0
22	**Net Utility Plant**	$62,452	($1,897)	$60,555	$0	$60,555
23	Customers Advances for Construction	(386)	0	(386)	0	(386)
24	Prepayments	730	0	730	0	730
25	Plant Acquisition Adjustment	(19)	0	(19)	0	(19)
26	Materials & Supplies - Fuel	297	(118)	179	0	179
27	- Other	1,281	0	1,281	0	1,281
28	Working Cash	481	(34)	447	0	447
29	Misc. Deferred Debits	1,709	(269)	1,440	0	1,440
30	Misc. Deferred Credits	0	0	0	0	0
31	IERCO Investment	(69)	0	(69)	0	(69)
32	**Total Average Rate Base**	$66,476	($2,318)	$64,158	$0	$64,158
33	**Rate of Return**	6.45%		7.71%		8.95%
34	**Implied Return on Equity**	5.00%		7.77%		10.50%

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IDAHO POWER COMPANY
Summary of Proposed Adjusted Oregon Results
UE-92 Test Year Based on 1993
(000)
Staff Recommendation

Income Tax Calculations	1993 Adjusted Results Per Company (1)	Staff Adjustments (2)	1993 Staff Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
Book Revenues	$21,990	$0	$21,990	$1,329	$23,319
Book Expenses Other than Depreciation	13,413	(981)	12,432	24	12,456
State Tax Depreciation	2,761	(28)	2,733	0	2,733
Interest	2,619	(279)	2,340	0	2,340
Book-Tax (Schedule M) Differences	521	(49)	472	0	472
State Taxable Income	$2,676	$1,337	$4,013	$1,305	$5,318
State Income Tax @ 6.3%	$171	$89	$260	$82	$342
Less: Idaho Tax Credit	82	0	82	0	82
Net State Income Tax	$89	$89	$178	$82	$260
Additional Tax Depreciation	264	0	264	0	264
Other Schedule M Differences	0	0	0	0	0
Federal Taxable Income	$2,323	$1,248	$3,571	$1,223	$4,794
Federal Tax @ 35%	$813	$437	$1,250	$428	$1,678
ITC	0	0	0	0	0
Current Federal Tax	$813	$437	$1,250	$428	$1,678
Prior Year Deficiency	$142	($117)	$25	0	$25
ITC Adjustment					
Deferral	$0	$0	$0	$0	$0
Restoration	22	0	22	0	22
Total ITC Adjustment	($22)	$0	($22)	$0	($22)
Provision for Deferred Taxes	$482	($191)	$291	$0	$291
Total Income Tax	$1,504	$219	$1,723	$510	$2,233

95-1240
Addendum 2
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IDAHO POWER COMPANY
Proposed Adjustments to Oregon Results
UE 92 Test Year Based on 1993
(000)
Staff Recommendation

		Tax Effect of ROR Change/ Remove ST Int. (S-1)	Remove Deferred Costs SFAS 106 & 112 (S-2)	General Wage Adjustment (S-3)	Workforce Update (S-4)	BM 5 Property Tax Reduction (S-5)	Company Correction Conserv. Prog. (S-6)
1	Operating Revenues						
2	Sales to Consumers	$0	$0	$0	$0	$0	$0
3	Other Revenues	0	0	0	0	0	0
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes						
6	Operation & Maintenance						
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs	0	0	0	0	0	0
9	Other Oper.& Maint.	0	0	(24)	(38)	0	(54)
10	**Total Operation & Maintenance**	$0	$0	($24)	($38)	$0	($54)
11	Depreciation & Amortization	0	(49)	0	0	0	0
12	Taxes Other than Income	0	0	(2)	(2)	(107)	0
13	Income Taxes	77	23	10	16	42	21
14	IERCO Operating Income						
15	**Total Operating Expenses and Taxes**	$77	($26)	($16)	($24)	($65)	($33)
16	**Utility Operating Income**	($77)	$26	$16	$24	$65	$33
17	Average Rate Base						
18	Utility Plant in Service	$0	$0	($5)	($6)	$0	$0
19	Accumulated Depreciation						
20	Accumulated Deferred Income Taxes						
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	($5)	($6)	$0	$0
23	Customers Advances for Construction	0	0	0	0	0	0
24	Prepayments	0	0	0	0	0	0
25	Plant Acquisition Adjustment	0	0	0	0	0	0
26	Materials & Supplies - Fuel						
27	- Other						
28	Working Cash	0	0	(1)	(2)	0	(2)
29	Misc. Deferred Debits		(269)				
30	Misc. Deferred Credits						
31	IERCO Investment						
32	**Total Average Rate Base**	$0	($269)	($6)	($8)	$0	($2)
33	**Revenue Requirement Effect**	$128	($83)	($27)	($41)	($108)	($55)

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IDAHO POWER COMPANY
Proposed Adjustments to Oregon Results
UE 92 Test Year Based on 1993
(000)
Staff Recommendation

		Reverse Prior Year Tax Deficiency (S-7)	Sch. M/ Deferred Tax Allocation (S-8)	QF Cost @ Oregon Rates (S-9)	Remove Milner Project /IERCO Net (S-10)	Fuel Inventory (S-11)	Remove Year-end Depreciation (S-12)
1	Operating Revenues						
2	Sales to Consumers	$0	$0	$0	$0	$0	$0
3	Other Revenues	0	0	0	(2)	0	0
4	**Total Operating Revenues**	$0	$0	$0	($2)	$0	$0
5	Operating Expenses and Taxes						
6	Operation & Maintenance						
7	Net Variable Power Costs	$0	$0	($376)	($262)	$0	$0
8	Fixed Power Costs	0	0	0	0	0	0
9	Other Oper.& Maint.	0	0	0	(71)	0	0
10	**Total Operation & Maintenance**	$0	$0	($376)	($333)	$0	$0
11	Depreciation & Amortization	0	0	0	(42)	0	(49)
12	Taxes Other than Income	0	0	0	(30)	0	0
13	Income Taxes	(117)	(192)	149	182	2	(0)
14	IERCO Operating Income				243		
15	**Total Operating Expenses and Taxes**	($117)	($192)	($227)	$20	$2	($50)
16	**Utility Operating Income**	$117	$192	$227	($22)	($2)	$50
17	Average Rate Base						
18	Utility Plant in Service	$0	$0	$0	($2,093)	$0	$0
19	Accumulated Depreciation				27		25
20	Accumulated Deferred Income Taxes		96		59		
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$96	$0	($2,007)	$0	$25
23	Customers Advances for Construction	0	0	0	0	0	0
24	Prepayments	0	0	0	0	0	0
25	Plant Acquisition Adjustment	0	0	0	0	0	0
26	Materials & Supplies - Fuel					(118)	
27	- Other						
28	Working Cash	0	0	(15)	(13)	0	0
29	Misc. Deferred Debits					0	
30	Misc. Deferred Credits						
31	IERCO Investment						
32	**Total Average Rate Base**	$0	$96	($15)	($2,020)	($118)	$25
33	**Revenue Requirement Effect**	($196)	($307)	($382)	($265)	($15)	($80)

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IDAHO POWER COMPANY
Proposed Adjustments to Oregon Results
UE 92 Test Year Based on 1993
(000)
Staff Recommendation

		Remove Informational Advertising (S-13)	Revenue Sensitive Costs (S-14)	Total Adjustments
1	Operating Revenues			
2	Sales to Consumers	$0	$0	$0
3	Other Revenues	0	0	(2)
4	**Total Operating Revenues**	$0	$0	($2)
5	Operating Expenses and Taxes			
6	Operation & Maintenance			
7	Net Variable Power Costs	$0	$0	($638)
8	Fixed Power Costs	0	0	0
9	Other Oper.& Maint.	(15)	0	(202)
10	**Total Operation & Maintenance**	($15)	$0	(840)
11	Depreciation & Amortization	0	0	(140)
12	Taxes Other than Income	0	0	(141)
13	Income Taxes	6	0	219
14	IERCO Operating Income	0		243
15	**Total Operating Expenses and Taxes**	($9)	$0	($660)
16	**Utility Operating Income**	$9	$0	$658
17	Average Rate Base			
18	Utility Plant in Service	$0	$0	($2,104)
19	Accumulated Depreciation			52
20	Accumulated Deferred Income Taxes			155
21	Accumulated Deferred Inv. Tax Credit	0	0	0
22	**Net Utility Plant**	$0	$0	($1,897)
23	Customers Advances for Construction	0	0	0
24	Prepayments	0	0	0
25	Plant Acquisition Adjustment	0	0	0
26	Materials & Supplies - Fuel			(118)
27	- Other			0
28	Working Cash	(1)	0	(34)
29	Misc. Deferred Debits			(269)
30	Misc. Deferred Credits			0
31	IERCO Investment			0
32	**Total Average Rate Base**	($1)	$0	($2,318)
33	**Revenue Requirement Effect**	($15)	$0	($1,447)

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IDAHO POWER COMPANY
Proposed Adjustments to Oregon Results
UE 92 Test Year Based on 1993
(000)
Staff Recommendation

		Tax Effect of ROR Change/ Remove ST Int. (S-1)	Remove Deferred Costs SFAS 106 & 112 (S-2)	General Wage Adjustment (S-3)	Workforce Update (S-4)	BM 5 Property Tax Reduction (S-5)	Company Correction Conserv. Prog. (S-6)
34	Book Revenues						
35	Book Expenses Other than Depreciation	0	0	(26)	(40)	(107)	(54)
36	State Tax Depreciation		0	0	0	0	0
37	Interest	(195)	(10)	(0)	(0)	0	(0)
38	Book-Tax (Schedule M) Differences	0	(49)	0	0	0	0
39	State Taxable Income	$195	$59	$26	$40	$107	$54
40	State Income Tax @ 6.304%	$13	$4	$2	$3	$7	$4
41	State Tax Credit						
42	**Net State Income Tax**	$13	$4	$2	$3	$7	$4
43	Additional Tax Depreciation	0	0	0	0	0	0
44	Other Schedule M Differences						
45	Federal Taxable Income	$182	$55	$24	$38	$100	$50
46	Federal Tax @ 35%	$64	$19	$9	$13	$35	$18
47	ITC	0	0	0	0	0	0
48	**Current Federal Tax**	$64	$19	$9	$13	$35	$18
49	**Prior Year Deficiency**	$0	$0	$0	$0	$0	$0
50	ITC Adjustment						
51	Deferral	$0	$0	$0	$0	$0	$0
52	Restoration	0	0	0	0	0	0
53	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0
54	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0
55	**Total Income Tax**	$77	$23	$10	$16	$42	$21

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IDAHO POWER COMPANY
Proposed Adjustments to Oregon Results
UE 92 Test Year Based on 1993
(000)
Staff Recommendation

		Reverse Prior Year Tax Deficiency (S-7)	Sch. M/ Deferred Tax Allocation (S-8)	QF Cost @ Oregon Rates (S-9)	Remove Milner Project /IERCO Net (S-10)	Fuel Inventory (S-11)	Remove Year-end Depreciation (S-12)
34	Book Revenues						
35	Book Expenses Other than Depreciation	0	0	(376)	(363)	0	0
36	State Tax Depreciation	0	0	0	(28)	0	0
37	Interest	0	4	(1)	(74)	(4)	1
38	Book-Tax (Schedule M) Differences	0	0	0	0	0	0
39	State Taxable Income	$0	($4)	$377	$465	$4	($1)
40	State Income Tax @ 6.304%	$0	($0)	$25	$31	$0	($0)
41	State Tax Credit						
42	**Net State Income Tax**	$0	($0)	$25	$31	$0	($0)
43	Additional Tax Depreciation	0	0	0	0	0	0
44	Other Schedule M Differences						
45	Federal Taxable Income	$0	($3)	$351	$434	$4	($1)
46	Federal Tax @ 35%	$0	($1)	$123	$152	$1	($0)
47	ITC	0	0	0	0	0	0
48	**Current Federal Tax**	$0	($1)	$123	$152	$1	($0)
49	**Prior Year Deficiency**	($117)	$0	$0	($0)	$0	$0
50	ITC Adjustment						
51	Deferral	$0	$0	$0	$0	$0	$0
52	Restoration	0	0	0	0	0	0
53	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0
54	**Provision for Deferred Taxes**	$0	($191)	$0	$0	$0	$0
55	**Total Income Tax**	($117)	($192)	$149	$182	$2	($0)

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IDAHO POWER COMPANY
Proposed Adjustments to Oregon Results
UE 92 Test Year Based on 1993
(000)
Staff Recommendation

		Remove Informational Advertising (S-13)	Revenue Sensitive Costs (S-14)	Total Adjustments
34	Book Revenues			$0
35	Book Expenses Other than Depreciation	(15)	0	(981)
36	State Tax Depreciation	0	0	(28)
37	Interest	(0)	0	(279)
38	Book-Tax (Schedule M) Differences	0	0	(49)
39	State Taxable Income	$15	$0	$1,337
40	State Income Tax @ 6.304%	$1	$0	$89
41	State Tax Credit			
42	**Net State Income Tax**	$1	$0	$89
43	Additional Tax Depreciation	0	0	0
44	Other Schedule M Differences			
45	Federal Taxable Income	$14	$0	$1,248
46	Federal Tax @ 35%	$5	$0	$437
47	ITC	0	0	0
48	**Current Federal Tax**	$5	$0	$437
49	**Prior Year Deficiency**	$0	$0	($117)
50	ITC Adjustment			
51	Deferral	$0	$0	$0
52	Restoration	0	0	0
53	**Total ITC Adjustment**	$0	$0	$0
54	**Provision for Deferred Taxes**	$0	$0	($191)
55	**Total Income Tax**	$6	$0	$219

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IDAHO POWER COMPANY
General Rate Case - UE 92
(000)

INPUT ASSUMPTIONS

COST OF CAPITAL	AMOUNTS	% OF CAPITAL	COST	WEIGHTED COST
Long Term Debt	$663,144	45.48%	8.02%	3.65%
Preferred Stock	132,751	9.10%	5.90%	0.54%
Common Equity	662,367	45.42%	10.50%	4.77%
Total	$1,458,262	100.00%		8.95%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectibles/OPUC Fees	0.00375
Other Taxes-Franch.	0.01400
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income**	0.98225
State Income Tax @ 6.3	0.06188
Federal Taxable Income	0.92037
Federal Income Tax @ 35%	0.32213
ITC	0.00000
Current FIT	0.32213
ITC Adjustment/Env. Tax	0.00000
Total Income Taxes	0.38401
Total Revenue Sensitive Costs	0.40176
Utility Operating Income	0.59824
Net-to-Gross Factor	1.67157

* Uncollectible Rate	0.00250
OPUC Fee	0.00125
Total	0.00375

**State Income Tax	
Idaho	0.05900
Oregon	0.00400
Total	0.06300

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Addendum 2
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ADDENDUM NO. 3
TO SETTLEMENT STIPULATION

Idaho Power agrees to implement a policy of wintertime restriction on termination of service for its Oregon residential customers. This policy is designed to tailor Idaho Power's service disconnection procedures to the cold climate in eastern Oregon.

This policy of wintertime restriction on termination of residential service, described below, will be in effect for one year from the date this Settlement Stipulation is approved by the Public Utility Commission of Oregon. After the policy has been implemented for the period of one year, Idaho Power may review the policy to determine its continuing workability. If Idaho Power discovers no significant problems with the policy, then the policy of wintertime restriction on termination of residential service will continue automatically for every year thereafter.

If at the end of one year, or at any time thereafter, Idaho Power discovers significant problems with the policy or its implementation, then Idaho Power shall contact the signatories to this Settlement Stipulation and the Public Utility Commission and notify them of its intent to cease its policy of wintertime restriction on termination of residential service. Idaho Power agrees that, prior to discontinuing its policy, it will negotiate in good faith with the signatory parties to resolve problems Idaho Power has with the ongoing policy.

Nothing herein restricts the right of any party to file a complaint with the Public Utility Commission to enforce this policy as long as it remains in effect.

Policy for Wintertime Restriction on Termination of Residential Service:

1. Wintertime restriction on termination of residential service. Except as provided in OAR 860-21-315 (emergency disconnection), Idaho Power may not terminate service or threaten to terminate service during the months of December through February to any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, elderly or infirm persons.
2. Definitions:
   a. Children is defined as persons 18 years of age or younger, but not emancipated minors.
   b. Elderly is defined as persons 62 years of age or older.
   c. Infirm is defined as persons whose physical health or safety would be seriously impaired by termination of utility service.
3. Time-Payment Plan. Any residential customer who declares that he or she is unable to pay in full for electrical service and whose household includes children, elderly, or infirm persons must be offered the opportunity to enter into a time-payment plan. Idaho Power will offer customers a choice of payment agreements as described in OAR 860-21-415. No customer may be required to establish a time-payment plan. If the customer does not pay or enter into a time-payment plan, Idaho Power may disconnect service on or after March 1, after complying with the procedures of OAR 860-21-405.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

Exhibit 203
Docket No. UE 92 – Staff's Settlement Proposals

February 28, 2024

Attachment 3 - Response to Staff's DR 25

Post-it® Fax Note 7671	Date 9-1	# of pages ▶ 14
To RIC GALE	From RAY LAMBETH	
Co./Dept. IDAHO POWER	Co. OPUC	
Phone #	Phone # (503) 378-6917	
Fax # (208) 388-6936	Fax #	

Oregon
PUBLIC
UTILITY
COMMISSION

September 1, 1995

TO ALL PARTIES IN DOCKET UE 92

Enclosed are the following documents describing OPUC staff's settlement proposals in Docket UE 92:

1. A brief narrative summary of staff's issues and the revenue requirement effect of each;

2. Financial tables showing the components of each proposed adjustment to the company's filing and the resulting proposed revenue change;

3. A table showing staff's proposed rates as a percentage of LRIC; and

4. Summary workpapers.

Please remember that the enclosed staff proposals are <u>FOR SETTLEMENT PURPOSES ONLY</u>. They are distributed in aid of productive settlement discussions and do not bind staff to any positions in its formal case.

Scheduled settlement conferences will begin at 9:30 a.m. on Monday, September 11, in the Small Hearing Room on the second floor of the PUC Building, 550 Capitol Street NE, in Salem.

Call Mike Weirich ((503) 378-6986) or me if you want to discuss settlement matters before the conference.

T. Ray Lambeth

T. Ray Lambeth
Program Manager
Energy Revenue Requirements
(503) 378-6917
Fax: (503) 373-7752

17/2259HH

Enclosures

cc: Bill Warren
Mike Kane
Mike Weirich

John A. Kitzhaber
Governor

550 Capitol St. NE
Salem, OR 97310-1380
(503) 378-5849

Attachment 3 - Response to Staff's DR 25

IDAHO POWER COMPANY
Staff Issues Summary
UE 92 - 1993 Test Year
($ x 1,000)

Item	Staff	Issue	Revenue Requirement Effect
S-8	EK	**Allocation of Deferred Income Taxes/Schedule M Timing Differences** The company used different allocation factors in assigning deferred income tax expense and related schedule M adjustments (timing differences used in calculating income taxes) to Oregon. This caused overall allocated to Oregon income tax expense to be too high. Staff proposes to reallocate deferred income tax expense using the same allocation factor (net taxable income) that the company used in allocating the schedule M adjustments.	(307)
S-9	TR/JB	**Qualifying Facility Purchased Power Costs Priced at Oregon Avoided Costs Rates** Staff proposes to reduce the company's test year affiliated interest (AI) and non-affiliated qualifying facility (QF) energy costs of $8.4 million and $25.7 million, respectively for QF contracts. Company filed QF costs are based on Idaho Commission avoided cost rates. However, staff's adjusted QF costs of $3.6 million for AI QF contracts and $20.5 million for third party QF contracts are based on Oregon Commission avoided cost rates.	(382)
S-10	JB	**Remove Milner Project/IERCO Net Income/Adjust Bridger Coal Costs** Staff proposes to remove the revenue requirement associated with the Milner project and to reduce the Bridger fuel cost to $.86 MMBtu. The Bridger fuel price is adjusted to reflect the Bridger Coal Company coal cost per ton in 1993. IERCO net income (the margin between price and cost) is also removed to be consistent with this change. The variable power cost component of this adjustment is based upon the company's response to staff DR 77, a variable power cost model run that removes Milner from the resource stack and reduces the Bridger fuel price to $.86 MMBtu. An alternative rate treatment of Milner might be to price the plant for revenue requirement purposes using an avoided cost method.	(362)
S-11	JB	**Fuel Inventory** Staff proposes three changes to Bridger fuel inventory resulting in an overall reduction to rate base. The first change lowers the Bridger fuel price as discussed in adjustment S-10 to $16.64/ton. The second change increases the Bridger capacity factor reflecting higher Bridger output based upon the company's response to staff DR 77. The third change decreases the number of days of inventory to be consistent with PacifiCorp's Bridger inventory.	(15)
S-12	SS	**Remove Year-end Depreciation Update** Staff proposes to remove IPC's adjustment to annualize depreciation expense using December 1993 as the base. The company's filed case is generally based on average results and the year-end depreciation request does not match average operating results.	(80)
S-13	LS	**Remove Informational Advertising** Staff concludes that this advertising all relates to Co-op advertising for promotional programs for high efficiency heat pumps, water heaters, and other measures which are directly related to electricity use and proposes to remove the expense.	(15)
S-14	EK	**Revenue Sensitive Costs** The company's filed net-to-gross factors excluded an allowance for uncollectible accounts, OPUC Fee, and Oregon franchise taxes (revenue sensitive costs). Staff proposes to include these revenue sensitive costs in its net-to-gross factors.	

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 425

IDAHO POWER COMPANY

CONFIDENTIAL
Exhibit 204
Faulkner Ranch Forecast

February 28, 2024

CONFIDENTIAL

THIS EXHIBIT IS CONFIDENTIAL PER GENERAL PROTECTIVE ORDER NO. 23-132 AND IS PROVIDED SEPARATELY

CERTIFICATE OF SERVICE

I certify that on this February 28, 2024 a true and correct copy of **Idaho Power Company's Reply Testimony and Exhibits of Jessica G. Brady (Idaho Power/200-204)** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 425

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Dated February 28, 2024.

Cole Albee

Cole Albee
Paralegal
McDowell Rackner Gibson PC