BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 384

In the Matter of	)
	)
IDAHO POWER COMPANY,	)
	)
2021 Annual Power Cost Update (APCU).	)
	)
October Update.	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF THE

OREGON CITIZENS' UTILITY BOARD

January 29, 2021

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and occupation.

A. My name is Bradley G. Mullins. I am a Consultant for MW Analytics, an independent consulting firm representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit CUB/101.

Q. Please identify the party on whose behalf you are testifying.

A. I am testifying on behalf of the Oregon Citizens' Utility Board ("CUB").

Q. What is the purpose of your testimony?

A. I will discuss my initial review of the 2021 October Update of Idaho Power Company ("Idaho Power"), including the supporting testimony of Idaho Power witness Nicole Blackwell.

Q. What was the scope of your initial review?

A. I reviewed Idaho Power's 2021 Annual Power Cost Update ("APCU") October Update filing and issued several discovery requests. Idaho Power's responses to discovery requests, which are relevant to this testimony, have been attached as Exhibit CUB/102. In performing my review, I did not review the AURORA power cost modeling supporting Idaho Power's filing. I will provide a more comprehensive analysis in response to Idaho Power's March Update, including an analysis of Idaho Power's AURORA modeling.

Q. Please summarize your review.

A. In reviewing Idaho Power's workpapers and discovery responses, I identified several issues that I recommend be updated in future testimony. Specifically, I recommend Idaho Power:

- Remove the allocation of Energy Imbalance Market ("EIM") benefits to third-party Bonneville Power Administration ("BPA") loads in its Balancing Area,
- Perform an updated analysis of the factors used in Docket No. UE 19 repricing methodology using contemporaneous data;
- Remove the costs of fines, citations, donations, management overtime, and 50% of incentives from the Bridger Coal Company ("BCC") budget, as these items are not typically recoverable in Oregon Rates;
- Remove a management fee from the BCC budget since Idaho Power already earns a return on its BCC investment in rate base;
- Provide clarification on a provision for trains, royalties, and depreciation added to the cost of coal at the Jim Bridger power plant;
- Provide clarification on an additional 16% amount added to the per-ton cost of coal from BCC; and,
- Update the Partner Dispatch sales amounts from the Valmy power plant to be based on experience in 2020.

II. EIM BENEFITS

Q. How does Idaho Power calculate the EIM benefits included in its power supply forecast?

A. Idaho Power's calculation of the EIM Benefits included in its power supply forecast may be found in Exhibit Idaho Power/106. As can be seen, Idaho Power's estimate of EIM benefits in the forward period is based on the amount of benefits calculated by the California Independent System Operator ("CAISO"), subject to three adjustments. First, Idaho Power makes an adjustment to recalculate the benefits based on zero cost hydro. Second, Idaho Power makes an adjustment assigning a price to hydro generation. Third, Idaho Power deducts 7.24% of the benefit, which it attributes to third-party BPA loads.

Q. Do you have any concerns with Idaho Power's calculation?

A. Yes. My primary concern is related to Idaho Power's assumptions surrounding the benefits attributable to third-party loads.

Q. What third-party loads are located in Idaho Power's balancing area?

A. Several rural electric utilities and cooperatives are located in Idaho Power's balancing area, including a portion of the Oregon Trail Electric Consumer's Cooperative load. The third-party loads located in Idaho Power's Service receive requirements services under a transfer service agreement from BPA, which must purchase transmission services from Idaho Power in order to serve these loads.

Q. Do these third-loads benefit from the EIM?

A. These third-party do not benefit from the EIM in the form of reduced power supply costs in the same manner as Idaho Power. Accordingly, Idaho Power's assumption that 7.24% of the EIM benefits in its balancing area are recognized by third-party loads is not an accurate assumption.

Q. How does Idaho Power recognize benefits in the EIM?

A. The primary source of benefits from participating in the EIM comes in the form of imbalance revenues Idaho Power earns by dispatching its participating resources in accordance with EIM instructions in both the fifteen-minute market ("FMM") and five-minute or real-time market ("RT"). Idaho Power is paid to either increase or decrease the output of a resource relative to the scheduled output based on the needs of the system at each time interval. The mechanics of the EIM can be found in California Independent System Operator Tariff Section 29.11.

Q. Do loads and non-participating resources recognize net benefits in the EIM?

A. No. Loads and non-participating resources must also pay imbalance settlements, although the imbalances payments of loads and non-participating resources are benefit neutral. The settlements paid or received by loads are not driven by market instructions, but rather, based on the difference between scheduled and actual load multiplied by the EIM price. Since one expects the actual loads to have an equal probability of being higher or lower than the scheduled amount—that is, there is no scheduling bias—the EIM is not expected to result in a net cost or benefit with respect to loads. The same can be said of non-participating resources. These loads and non-participating resources were required to pay imbalance charges before the EIM, albeit at monthly prices, not the locational prices calculated by the EIM. Other than the elimination of certain penalty provisions in Schedule 4, the loads and non-participating resourced did not recognize any appreciable benefit by moving to settlements calculated on locational prices when Idaho Power joined the EIM.

Q. Do any of the third-party BPA loads possess EIM participating resources in Idaho Power's balancing area?

A. No. In response to CUB Data Request 14, Idaho Power confirmed that "[t]here is no dispatchable generation located within Idaho Power's balancing area participating in the EIM that is owned by the third-party entities."[1] Thus, there are no third-party entities located in Idaho Power's balancing area that are capable of responding to EIM market instructions in order to recognize instructed imbalance revenues in the EIM. BPA cannot earn instructed imbalance settlement revenues by dispatching its resources in accordance with market instructions into Idaho Power's service area. BPA and its requirements customers in Idaho Power's balancing area do not recognize a portion of the benefits associated with Idaho Power's participation in the EIM.

Q. What do you recommend?

A. I recommend eliminating the 7.24% deduction that Idaho Power applies to the EIM benefit amount in connection with third-party entities.

III. UE 195 REPRICING METHODOLOGY

Q. What is the UE 195 repricing methodology?

A. In Exhibit Idaho Power/104 lines 18, 20, 22, and 24, several factors are identified to reallocate and reprice the purchases and sales forecast in the AURORA model. The exhibit reprices the sales and purchases from AURORA based on historically issued forward price curves. The identified factors are used to reduce the revenue received from sales transactions and to increase the cost of purchase transactions. The adjustment occurs on a diurnal basis, based on

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1 Exhibit CUB/102 at 7.

separate adjustment factors applied to heavy-load-hour ("HLH") and light-load-hour ("LLH") forward pricing.

Q. Did you request for Idaho Power to explain the repricing methodology?

A. Yes. In response to CUB Data Requests 11, Idaho Power was requested to provide workpapers supporting the repricing analysis. Idaho Power stated that the specific repricing percentages in Exhibit Idaho Power/104 lines 18, 20, 22, and 24 were prescribed by the Commission Order No. 08-238 in Docket No. UE 195.[2] In the response, however, Idaho Power was unable to provide any workpapers supporting the percentages. Further, in response to CUB Data Request 12, Idaho Power was requested to provide a narrative explanation for the repricing methodology.[3] Idaho Power responded by providing a quote from the stipulation Docket No. UE 195, which identified the respective repricing percentages for purchases and sales in HLH and LLH periods.

Q. Do you agree with Idaho Power that Commission Order No. 08-238 prescribed the repricing percentages that must be used to establish forecast power supply expenses?

A. Not necessarily. It is true that the repricing percentages were identified in the Stipulation in Docket No. UE 195. That Stipulation, however, was issued on March 14, 2008—nearly 13 years ago. The Stipulation did not appear to prohibit updating the percentages and refining the underlying methodology in future filings in response to changing circumstances and conditions. At a minimum, it is reasonable to study whether the parameters used to develop the repricing percentages in the 2008 Stipulation continue to be valid more than a decade later.

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2 Exhibit CUB/102 at 4.
3 Exhibit CUB/102 at 5

Q. How does Idaho Power determine the amount of sales and purchases that occur in HLH and LLH periods?

A. Rather than using the actual HLH and LLH sales and purchases calculated in the AURORA Model, Idaho Power relies on fixed percentages to allocate purchases between HLH and LLH periods. These percentages can be identified in Exhibit Idaho Power/105, Lines 34, 36, 38, and 40.

Q. Did you request Idaho Power to provide support for the HLH and LLH percentages?

A. Yes. In CUB Data Request 13, Idaho Power was asked to provide support for the HLH and LLH percentages.[4] In its response, Idaho Power noted that the specific HLH and LLH percentages were not identified in the Stipulation in UE 195. Rather, Idaho Power pointed its response to Staff's Data Request No. 10 in UE 195 to support the fixed HLH and LLH percentages.[5] Thus, there appears to be no requirement in the UE 195 Stipulation which would require the use of the specific, fixed HLH and LLH percentages identified in Idaho Power/105.

Q. Have you reviewed the AURORA output to determine if the percentages are valid?

A. CUB is in the process of establishing access to the AURORA model and will further evaluate the AURORA modeling at a later point in this proceeding.

Q. Based on your review of the repricing methodology, what is your recommendation?

A. I recommend that Idaho Power provided an updated analysis to evaluate whether the repricing factors from Docket No. UE 195 continue to be valid under current market conditions. Further, I recommend that Idaho Power perform a comparison between the HLH and LLH purchases and sales forecast in AURORA to the fixed HLH and LLH percentages identified in Idaho Power/105. While the factors, and the associated repricing methodology, were described

4 Exhibit CUB/102 at 6.
5 *See* Confidential Exhibit CUB/103.

in the UE 195 Stipulation, it is not unreasonable for Idaho Power's power supply forecasting methodology to change over time in response to changing circumstances. It is not reasonable to assume that the percentages calculated in 2008 in Docket No. UE 195 are binding in perpetuity. If consumers are still using energy from electricity transmitted on wires in the year 2099, for example, the same methodology Idaho Power deployed in 2008 may no longer be relevant. At a minimum, it is reasonable to periodically review the methodology and assumptions, which is what I recommend in this docket.

IV. JIM BRIDGER COAL COSTS

Q. What is the purpose of this section of testimony?

A. In this section of testimony, I discuss several issues related to the cost of fuel at the Jim Bridger coal fired power plant. In CUB Data Request 7, Idaho Power was requested to provide detail behind its calculation of the fuel supply costs it assumed for Jim Bridger.[6] In response, Idaho Power provided a high-level budget prepared by BCC, as well as some supporting workpapers. In general, the information Idaho Power provide was highly summarized and less detailed that the information that is traditionally provided by BCC in its budgeting process. For example, detail supporting the forecast of depreciation expenses, royalty expenses and labor expenses were not included in the data Idaho Power provided in response to CUB's data requests. Accordingly, further questions and issues may be identified to the extent that more detailed information is supplied at a later point in this proceeding.

[6] Exhibit CUB/102 at 1; Confidential Exhibit CUB/104.

a. Fines, Citations, Donations, and Incentives

Q. Did Idaho Power make any adjustments to the bcc budget to remove costs not recoverable in Oregon?

A. No. Items such as fines, citations, donations are typically not recoverable in Oregon rates. Further, incentive amounts are typically reduced by 50% in Oregon to reflect sharing between shareholders and ratepayers. In addition, I recommend that management overtime, which has historically been included in the cost of coal for BCC also be removed from power supply expense, since one expects managers to be required to perform some overtime in conjunction with their general duties and without requiring extra remuneration.

Q. What do you recommend?

A. I recommend that Idaho Power provide further documentation of the amount of fines, citations, and donations included in the cost of coal at BCC. Further, I recommend that Idaho Power provide further detail of the employee incentives detail of the incentives and management overtime included the BCC budget.

b. Management Fee

Q. Does the bridge coal cost budget supplied by Idaho Power include a management fee?

A. Yes. The management fee amount may be found in the confidential attachment to CUB DR 07, which I have attached as Confidential Exhibit CUB/104.

Q. What is the management fee?

A. A management fee is extra renumeration, above and beyond the mine's operating cost, meant to compensate for BCC's management of the mine assets.

Q. Are management fees commonly considered in regulated results of operations?

A. No. Typically, they are not. Utilities are compensated for their management of customer-funded utility property through the return on rate base embedded in revenue requirement.

Notwithstanding, there are instances where management fees are used to provide a utility with renumeration, in leu of a return on rate base. Specifically, where the assets of a utility have been fully depreciated to zero and the utility continues to provide services, a utility may include a management fee in rates to provide compensation for managing the utility assets. This scenario most commonly occurs with respect to pipeline assets. In Exhibit CUB/105, I provide an excerpt from the FERC Cost of Service Manual that discusses the use of a management fee, in leu of a return on rate base.

Q. Is it appropriate to include a management fee in the cost of coal from BCC?

A. No. Idaho Power includes its share of the assets of BCC in rate base and earns a return on equity in the BCC assets, which compensates it for the cost of managing BCC. Since management fees are only provided in leu of a return on rate base, where the utility property is fully depreciated, it is not appropriate to also provide Idaho Power with a management fee for the BCC assets included in the cost of fuel.

Q. What do you recommend?

A. I recommend that the management fee amounts be removed from the cost of coal from BCC.

c. <u>Additional Royalties and Depreciation</u>

Q. What issue have you identified related to additional royalties and depreciation included in Jim Bridger fuel costs?

A. In the confidential attachment to CUB Data Request 07, Tab "Bridger Detailed Fuel Cost," Idaho Power included an additional amount of royalties and depreciation expenses in the cost of fuel for the Jim Bridger Power Plant. These amounts may be found in the workpaper, column "AB", under the title "Train, Royalties & Deprec".[7] Idaho Power already recovers the

[7] See Confidential Exhibit CUB/104 at 4.

cost of royalties and deprecation in the base budget for BCC. Further, the cost of rail transportation from the neighboring Black Butte mine has already been factored into the cost of fuel for that plant. Accordingly, it does not appear to be necessary to include the additional royalties and deprecation amounts in the cost of fuel for the Jim Bridger power plant.

Q. What do you recommend?

A. I recommend Idaho Power clarify what the additional Royalties and Deprecation amounts represent and remove the amounts from the cost of fuel at Jim Bridger to the extent that the costs are already included in the budgets for BCC and Black Butte.

d. <u>Black Butte Price Escalation</u>

Q. What assumptions does Idaho Power make with respect to coal costs from the black butte mine?

A. For 2021, Idaho Power uses the existing contract rates. For 2022, however, Idaho Power applies escalation to the 2021 contract rate. This escalation may be observed in Confidential Exhibit CUB 103, Page 5 in the section "Black Butte Coal/Third Party Coal" under the line titled "$/Ton Assumed Forward."

Q. Does this escalation represent a known and measurable change?

A. No.

Q. What do you recommend?

A. Until a new contract has been executed, I recommend retaining the existing Black Butte contract rates in 2022. In the alternate, it is more appropriate for Idaho Power to assume that coal will be purchased at spot market rates in the absence of a new agreement with Black Butte. The spot market rate for coal from the powder river basin is relatively low compared to the rates assumed paid to Black Butte. Accordingly, assuming the coal were purchased on the spot market would result in a lower cost of fuel at the Jim Bridger power plant, in comparison to the existing Black Butte contract.

e. <u>Other BCC Cost Issues</u>

Q. Have you identified any other issues with respect to the cost of coal from bcc?

A. Yes. When determining the dollars per ton rate for coal from BCC, Idaho Power increase the total mine cost by 16%—or $30,600,000 total-mine, $10,200,000 Idaho Power share—through a hard-coded formula entry. This entry may be found in Confidential Exhibit 103, Tab "Bridger Prices and Supply" in the formula supporting the "Base $/Ton" values in cells "B11:C11."[8] I have been unable to reconcile those additional amounts included in BCC coal costs in Confidential Exhibit CUB/104, page 5, relative to the budged per-ton cost of coal included in Confidential Exhibit CUB/104, page 6.

Q. What do you recommend?

A. I recommend that Idaho Power clarify what the additional amounts included in the cost of BCC coal represent and provide workpapers supporting the amounts.

V. VALMY PARTNER DISPATCH

Q. Please provide some background on the Valmy coal fired power plant.

A. The Valmy plant is located in northern Nevada and is jointly owned by Idaho Power and Sierra Pacific Power Company. Idaho Power owns a 50% interest in the facility, which consists of two conventionally fired steam turbines. Valmy Unit 1 is scheduled to retire in 2021 and Valmy Unit 2 is scheduled to retire in 2025. In response to CUB Data Request 09, Idaho

8 Confidential Exhibit CUB/104 at 5.

Power noted that it exited participation in Valmy Unit 1 at the end of 2019 and continues to participate in Valmy 2.[9]

Q. How has Idaho Power been able to monetize the output from Valmy in the past?

A. In the past, Idaho Power has, at times, been able to sell its share of the output of Valmy Unit 1 and Unit 2 to Sierra Pacific Power Company at favorable rates. Idaho Power refers to theses sales as "Partner Dispatch" and includes a provision in its power supply costs to account for the benefit of these sales. Idaho power calculates the benefit associated with Partner Dispatch based on a 3-year rolling average of actual sales to Sierra Pacific. The current filing includes Partner Dispatch sales over the period 2017-2019, and includes an adjustment to account Idaho Power withdrawing from Valmy Unit 1 in 2019.

Q. What issue have you identified with respect to partner dispatch sales?

A. The Partner Dispatch sales to Sierra Pacific have been increasing almost every year. In response to CUB Data Request 15, Idaho Power provided the Partner Dispatch for 2020, which was approximately equal to the levels for 2019.[10] Notwithstanding, because Idaho stopped participating in Valmy Unit 1 at the end of 2019, the fact that the Partner Dispatch levels in 2020 were approximately equal to the 2019 levels is an indication of increasing demands on Sierra Pacific's System.

Q. Does the three-year average represent the partner dispatch benefits expected in the future test period?

A. Not necessarily. Since the Partner Dispatch amounts have been increasing every year, the three-year average likely understates the amount of Partner Dispatch in the forward period.

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9 Exhibit CUB/102 at 3.
10 Confidential Exhibit CUB/106

This is particularly true in this proceeding because, as a result of the retirement of Valmy 1, Sierra Pacific Power Company will have an even greater need for the remaining output from Valmy 2 in the future.

Q. What do you recommend?

A. I recommend including a forecast of Partner Dispatch benefits at Valmy based on the experience in calendar year 2020. Further, I recommend that no adjustment with respect to the Valmy 1 retirement, since Idaho Power withdrew from Valmy Unit 1 at the end of 2019 and the partner dispatch amounts in 2020 did not materially change.

Q. Does this conclude your opening testimony?

A. Yes.

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ABOUT

MW Analytics is the professional consulting practice of Brad Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the Western United States. Brad has sponsored expert witness testimony in over 70 regulatory proceeding encompassing a variety of subject matters, including revenue requirement, regulatory accounting, rate development, and new resource additions. Brad has also assisted his clients through numerous informal regulatory, legislative and energy policy matters. In addition to providing regulatory services, MW Analytics also provides advisory, energy marketing and other energy consulting services.

PRACTICE AREAS

MW Analytics has experience representing customer interests in litigated and informal regulatory proceedings, including the following subject areas:

- Revenue Requirement
- Power Cost Modeling
- Tax Provisions and Tax Reform
- Capital Additions and Forecasting
- Regulatory Accounting
- Depreciation Studies
- Ratemaking Mechanisms
- Integrated Resource Planning
- Avoided Cost Calculations
- Utility Plant Retirements

EDUCATION AND WORK EXPERIENCE

Brad has a Master of Accounting degree from the University of Utah. After obtaining his master's degree, Brad worked at Deloitte Tax in San Jose, California, where he was responsible for preparing corporate tax returns for multinational corporate clients and partnership returns for hedge fund clients. Brad was later promoted to a Tax Senior position in a national tax practice specializing research and development tax credit studies. Following Deloitte, Brad worked at PacifiCorp Energy, as an analyst involved in power cost modeling and forecasting. At PacifiCorp Brad was responsible for preparing power cost forecasts and supporting testimony for regulatory filings, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations.

REGULATORY APPEARANCES

Brad has sponsored expert witness testimony in the following regulatory proceedings:

Docket	Party	Topics
In re NV Energy's Fourth Amendment to its 2018 Integrated Resource Plan, PUCNv. Docket No. 20-07023	Smart Energy Alliance & Wynn Las Vegas, LLC	Transmission Planning
In re Cascade Natural Gas Corporation, 2020 General Rate Case, Wa.U.T.C. Docket No. UG-200568	Alliance of Western Energy Consumers	Revenue Requirement
In re Cascade Natural Gas Corporation, Petition to File Depreciation Study, Or.PUC Docket No. UM 2073	Alliance of Western Energy Consumers	Depreciation Rates
In re the Application of Rocky Mountain Power for Authority to Increase Current Rates By $7.4 Million to Recover Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $604 Thousand Under Tariff Schedule 93, Rec and So2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-582-EM-20	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the Complaint of Willamette Falls Paper Company and West Linn Paper Company against Portland General Electric Company, Or.PUC Docket No. UM 2107	Willamette Falls Paper Company	Consumer Direct Access, Tariff Dispute
In re The Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4, Wy.PSC Docket No. 2000-578-ER-20	Wyoming Industrial Energy Consumers	Power Cost Modeling
Avista Corporation 2021 General Rate Case, Or.PUC Docket No. UG 389	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re NW Natural Request for a General Rate Revision, Or.PUC Docket No. UG 388.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.	Alliance of Western Energy Consumers	Jurisdictional Allocation
In re Puget Sound Energy 2019 General Rate Case, Wa.UTC Docket No. UE 190529.	Alliance of Western Energy Consumers	Revenue Requirement, Coal Retirement Costs
Avista Corporation 2020 General Rate Case, Wa.UTC Docket No. UE-190334 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Application for Approval of a Safety Cost Recovery Mechanism, Or. PUC Docket No. UM 2026	Alliance of Western Energy Consumers	Ratemaking Policy
In re Avista Corporation, Request for a General Rate Revision, Or.PUC Docket No. UG 366.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric, 2020 Annual Update Tariff (Schedule 125), Or.PUC Docket No UE 359.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Transition Adjustment Mechanism, Or.PUC Docket No. UE 356.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Renewable Adjustment Clause, Or.PUC Docket No. UE 352.	Alliance of Western Energy Consumers	Single-issue Ratemaking
2020 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-20	Alliance of Western Energy Consumers	Revenue Requirement, Policy
In the Matter of the Application of MSG Las Vegas, LLC for a Proposed Transaction with a Provider of New Electric Resources, PUC Nv. Docket No. 18-10034	Madison Square Garden	Customer Direct Access

Puget Sound Energy 2018 Expedited Rate Filing, Wa.UTC Dockets UE-180899/UG-180900 (Cons.).	Alliance of Western Energy Consumers	Revenue Requirement, Settlement
Georgia Pacific Gypsum LLC's Application to Purchase Energy, Capacity, and/or Ancillary Services from a Provider of New Electric Resources, PUC Nv. Docket No. 18-09015.	Georgia Pacific	Customer Direct Access
Joint Application of Nevada Power Company d/b/a NV Energy for approval of their 2018-2038 Triennial Integrated Resource Plan and 2019-2021 Energy Supply Plan, PUCN Docket No. 18-06003.	Smart Energy Alliance	Resource Planning
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Or.PUC, Docket No. UE 347.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric Company Request for a General Rate Revision, Or.PUC Docket No UE 335.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or.PUC Docket No. UG 344.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170929.	Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In the Matter of Hydro One Limited, Application for Authorization to Exercise Substantial Influence over the Policies and Actions of Avista Corporation, Or.PUC, Docket No. UM 1897.	Alliance of Western Energy Consumers	Merger
Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision, Ut.PSC Docket No. 17-035-40	Utah Industrial Energy Consumers, & Utah Associated Energy Users	New Resource Addition
In re PacifiCorp, dba Rocky Mountain Power, for a CPCN and Binding Ratemaking Treatment for New Wind and Transmission Facilities, Id.PUC Case No. PAC-E-17-07	PacifiCorp Idaho Industrial Customers	New Resource Addition
In re PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE 327.	Alliance of Western Energy Consumers	Power Cost Deferral
In re PacifiCorp 2016 Power Cost Adjustment Mechanism, Wa.UTC Docket No. UE-170717	Boise Whitepaper, LLC	Power Cost Deferral
In re Avista Corporation 2018 General Rate Case, Wa.UTC Dockets UE-170485 and UG-170486 (Consolidated).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUCN. Docket No. 17-06003.	Smart Energy Alliance	Revenue Requirement
In re the Application of Rocky Mountain Power for Authority to Decrease Current Rates by $15.7 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates By $528 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy. PSC, Docket No. 20000-514-EA-17 (Record No. 14696).	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. UE-170033 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design

In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.	Industrial Customers of Northwest Utilities	Electric Vehicle Charging
In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re the Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing, Or.PUC, Docket No. UM 1802.	Industrial Customers of Northwest Utilities	Qualifying Facilities
In re Pacific Power & Light Co., Revisions to Tariff WN U-75, Advice No. 16-05, to modify the Company's existing tariffs governing permanent disconnection and removal procedures, Wa.UTC, Docket No. UE-161204.	Boise Whitepaper, LLC	Customer Direct Access
In re Puget Sound Energy's Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service, Wa.UTC, Docket No. UE-161123.	Industrial Customers of Northwest Utilities	Customer Direct Access
2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy
In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).	Industrial Customers of Northwest Utilities	Environmental Deferral
In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.	Arkansas Electric Energy Consumers	Net Metering
In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.	Arkansas Electric Energy Consumers	Net Metering
In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01	Utah Associated Energy Users	Power Cost Deferral
In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In re the Application of Rocky Mountain Power to Decrease Current Rates by \$2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by \$50 Thousand Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-292-EA-16.	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of \$32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15.	Wyoming Industrial Energy Consumers	Power Cost Modeling
In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re the Application of Rocky Mountain Power to Decrease Rates by \$17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by \$4.7 Million Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-472-EA-15.	Wyoming Industrial Energy Consumers	Power Cost Deferral
Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules, Wa.UTC, Docket No. UE-143932.	Columbia Rural Electric Association	Customer Direct Access / Customer Choice

In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation, Or.PUC, Docket No. UM 1662.	Industrial Customers of Northwest Utilities	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Or.PUC, Docket No. UM 1719.	Industrial Customers of Northwest Utilities	Resource Planning
In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions, Or.PUC, Docket No. UM 1623.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy
In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes, Wa.UTC, Docket No. UE-141368.	Industrial Customers of Northwest Utilities	Cost of Service
In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million, Wa.UTC, Docket No. UE-140762.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs, Wa.UTC, Docket No. UE-141141.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent, Wy.PSC, Docket No. 20000-446-ER-14.	Wyoming Industrial Energy Consumers	Power Cost Modeling
In re Avista Corporation, General Rate Increase for Electric Services, RE, Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015, Wa.UTC, Docket No. UE-140188.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design, Power Costs
In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Or.PUC, Docket No. UM 1689.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.	Industrial Customers of Northwest Utilities	Coal Retirement
In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck), Or.PUC, Docket No. UE 267.	Industrial Customers of Northwest Utilities	Customer Direct Access

CUB'S DATA REQUEST NO. 7:

Please provide the fuel supply cost calculations for the Jim Bridger coal plant, including detailed financial budgets and production estimates from the Bridger Coal Company.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 7:

Please see the confidential Excel file. The tab labeled "Bridger Detailed Fuel Calcs" provides the monthly fuel cost calculations for the test period including forecasted fuel purchases and consumption. The tab labeled "Bridger Prices and Supply" summarizes the Bridger Coal Company and third-party coal prices and volumes in the fuel forecast. The tab labeled "BCC Budget and Production" provides the detailed mine plan budget and production levels included in the forecast. Please note, forecasted coal consumption does not reflect AURORA modeled output, but rather the Company's outlook based on Idaho Power's Operations Plan.

CUB'S DATA REQUEST NO. 8:

Please provide the fuel supply cost calculations for the Valmy coal fired power plant.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 8:

Please see the confidential Excel file. The tab labeled "Valmy Detailed Fuel Calcs" provides the monthly fuel cost calculations for the test period including forecasted fuel purchases and consumption. The tab labeled "Valmy Spot Prices and Supply" summarizes the delivered coal pricing and volumes in the fuel forecast. Please note, forecasted coal consumption does not reflect AURORA modeled output, but rather the Company's outlook based on Idaho Power's Operations Plan.

<u>CUB'S DATA REQUEST NO. 9</u>:

Please provide an explanation of the current operation status of the Valmy coal plant, including any discussion regarding selling Idaho Power's interest to NV Energy or its subsidiaries, or other similar tolling arrangements, prior to the closure of the units.

<u>IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 9</u>:

Idaho Power exited participation in North Valmy Unit 1 at the end of 2019 and continues to participate in Unit 2. NV Energy, Idaho Power's ownership partner and the operating partner of the North Valmy plant, is participating in both Units 1 and 2. There have been no recent formal discussions regarding selling Idaho Power's interest in North Valmy to NV Energy or others. Idaho Power broached the subject of selling its ownership share to NV Energy or others prior to and during negotiations of the Framework Agreement signed in February 2019, but no parties were interested in acquiring Idaho Power's share of either of the North Valmy units.

<u>CUB'S DATA REQUEST NO. 11</u>:

Reference Idaho Power/104: Please provide the workpapers supporting the percentages on lines 18, 20, 22, and 24, used to reallocate prices used in the forecast period.

<u>IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 11</u>:

The percentages on lines 18, 20, 22, and 24 of Idaho Power/104 are prescribed by Commission Order No. 08-238.[1] Please refer to the Company's response to CUB's Data Request No. 12 for additional information.

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[1] *In the Matter of Idaho Power Company Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon*. Docket No. UE 195. Order No. 08-238, Appendix A, Pages 3-4. (April 28, 2008).

<u>CUB'S DATA REQUEST NO. 12</u>:

Reference Idaho Power/104: Please provide a narrative explanation of the mechanics of the UE 195 Settlement Methodology.

<u>IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 12</u>:

The re-pricing of Aurora-generated purchased power and surplus sales, as demonstrated in Idaho Power/104, follows a prescribed process that is outlined in the settlement stipulation approved by Order No. 08-238 in Docket No. UE 195. Pages 3-4 of Appendix A to Order No. 08-238 describe the specific methodology:

> The wholesale electric prices for purchased power and surplus sales determined by the Company's power supply model will be replaced with an average forward electric price curve calculated from the previous 12 months (the previous October through the September prior to the October filing) of daily Mid-Columbia heavy load (Mid-C HL) and light load (Mid-C LL) forward price curves for the period starting in April immediately following the April through March Test Period. Forward prices will be adjusted for inflation back one year using the most recent Global Insight Producer Price Index for Electric Power. For example: the October 2007 filing of normal power supply expenses, which would use the Test Period April 2008 – March 2009, would incorporate the average of daily price curves collected from October 2006 through September 2007 for the period April 2009 – March 2010. This average forward price curve would then be adjusted for inflation back one year to April 2008 – March 2009 (the Test Period) using the most recent Global Insight Producer Price Index for Electric Power.
>
> The volume of purchased power and surplus sales determined from the output of the Company's power supply model normalized run will be re-priced in the following manner:
>
> - Purchase Power
>   - Heavy Load – 3.9% above average Mid-C HL prices
>   - Light Load – 7.1% above average Mid-C LL prices
> - Surplus Sales
>   - Heavy Load – 3.6% below average Mid-C HL prices
>   - Light Load – 6.6% below average Mid-C LL prices

<u>CUB'S DATA REQUEST NO. 13</u>:

Reference Idaho Power/105: Please provide an explanation of the purpose of the percentages on rows 34, 36, 39, and 41.

<u>IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 13</u>:

It is Idaho Power's understanding that the percentages on lines 34, 36, [38], and [40] of Idaho Power/105 are the result of settlement in Docket No. UE 195, which implemented the APCU and PCAM. The settlement stipulation, joint testimony in support of stipulation, and the Commission order in Docket No. UE 195 are silent on these specific percentages. However, the Company points to its response to Staff's Data Request No. 10 in UE 195 to support its understanding that these percentages were the result of settlement. The response to Staff's Data Request No. 10, provided herein as Confidential Attachment 1, supports the specific percentages included in Idaho Power/105.

CUB'S DATA REQUEST NO. 14:

Reference Idaho Power/106: Please identify each third-party entity with load in Idaho power's balancing area, and the associated load assumed in the forecast period. Please also detail any dispatchable generation owned by each third-party entity located in Idaho Power's balancing area.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 14:

Idaho has a Network Integration Transmission Service Agreement (NITSA) with Bonneville Power Administration ("BPA") that serves load for three contracts: 1) the United States Bureau of Reclamation ('USBR"); 2) Priority Firm ("PF"); and 3) Oregon Trail Electric Cooperative ("OTEC"). The associated scheduled load included in Idaho Power/106 for USBR, PF and OTEC is 2,027,899 MWh.

Idaho also has a Network Integration Service Agreement with PacifiCorp that serves load for Imnaha. The associated load for Imnaha is 1,990 MWh, however, this load is not included in the forecast. Because this customer schedules load under 1 MW, Idaho Power does not charge them any EIM allocations for imbalance in accordance with Schedule 4 of the Idaho Power Open Access Transmission Tariff. As a result, the Company does not include any load ratio share adjustment for Imnaha as part of the EIM Benefit calculation included in Idaho Power/106.

There is no dispatchable generation located within Idaho Power's balancing area participating in the EIM that is owned by the third-party entities. However, Idaho Power's balancing area has non-participating generators owned by BPA that are settled in the EIM.

CUB Exhibit 103 is confidential and will be provided to parties that have executed Protective Order No. 20-394

CUB Exhibit 104 is confidential and will be provided to parties that have executed Protective Order No. 20-394

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

Accumulated Reserve for Depreciation. The cost of the investment in gross plant is recovered through the cost-of-service as Depreciation Expense. Accordingly, the depreciation expense is accumulated and is credited against the gross plant to reduce the remaining investment to be recovered. The remaining balance is the **Net Book Plant.** The net book plant represents the portion of gross plant that is not depreciated.

Pipeline U.S.A. has been in operation for 3 years. The accumulated reserve for depreciation balance computation is shown on A-4. The annual depreciation expense is added for each of the three years of operation to arrive at this balance. The net book plant is computed by subtracting the accumulated reserve for depreciation from the gross plant (See computation on A-2).

Also, as shown by A-4 and A-11, the facilities of Pipeline U.S.A. are 12% depreciated after 3 years of operation (3 yrs divided by 25 years, or $75,490/$629,080). In year 25, assuming Pipeline U.S.A. adds no additional rate base and that the depreciation rate remains unchanged, Pipeline U.S.A. would be fully depreciated, or in other words, Pipeline U.S.A. would have fully recovered its investment.

Over time, if the pipeline does not continue to add plant to its pipeline system, the time will come when the balance in the accumulated reserve for depreciation account will equal the gross plant. At this point, the investment is fully recovered and net plant will be zero. If the pipeline is continuing to operate after its investment is fully recovered, the Commission may consider a management fee. Otherwise, the pipeline would only be able to recover operating expenses and taxes other than income taxes and would have no opportunity to earn a profit as there would be no investment (rate base) to calculate a return.

Management Fee. When a pipeline is fully depreciated and the pipeline continues to provide service, the Commission has permitted rates which provide for the recovery of operating expenses, taxes and a reasonable management fee that is equivalent to no more than 10% of the pipeline's average pre-tax return during the years prior to when the pipeline became fully depreciated.

Accumulated Deferred Income Taxes (ADIT). This is the amount of income taxes collected by the pipeline but not yet needed to pay current income taxes. ADIT arise from differences in the methods of computing taxable income for the various taxing bodies and income for financial statement purposes. In ratemaking, ADIT associated with depreciation expense is the main component of total ADIT. ADIT associated with depreciation expense results because of differences due to the amount of depreciation expense recovered in a pipeline's rates versus the amount of depreciation expense that the pipeline can claim for tax purposes.

For tax purposes, a pipeline can choose an accelerated method of depreciation which produces a higher depreciation expense in the early years compared to the straight-line method which is used for rate purposes. A higher depreciation expense used as a deduction for income tax purposes in the early year’s results in a lower tax base and thus, the pipeline actually pays taxes in an amount less than the taxes collected in rates. This difference in the amount of taxes collected in rates and the amount of taxes actually paid are accumulated each year and are deducted from a pipeline's rate base as ADIT.

In essence, ratepayers are prepaying the income taxes and the pipeline will have use of these extra dollars until it has to pay more income taxes in subsequent years as its taxable deduction for depreciation decreases. That is, there will be a point in time when the depreciations expense computed on an accelerated basis for tax purposes will be less than the depreciation expense under the straight-line method. At this point, a pipeline will be collecting less taxes in rates than it needs to pay for income tax purposes. Thus, the monies accumulated as ADIT will be used to pay these taxes and the ADIT balance will start to decline.

CUB Exhibit 106 is confidential and will be provided to parties that have executed Protective Order No. 20-394

UE 384– CERTIFICATE OF SERVICE

I hereby certify that, on this 29th day of January, 2021, I served the foregoing **Confidential Testimony and Exhibits** in docket UE 384 upon the Commission and each party designated to receive confidential information pursuant to Order 20-394 by U.S. mail, postage prepaid.

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Respectfully submitted,

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