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11 March 2010

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

RE: **IPC-E-10-01**

Dear Ms. Jewell:

We are enclosing an original and seven (7) copies of the COMMENTS AND PROTEST OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER in the above case.

An additional copy is enclosed for you to stamp for our records.

Sincerely,

Nina Curtis

Nina Curtis
Richardson & O'Leary PLLC

encl.

REDACTED VERSION – The redacted portions of this document allegedly contain trade secrets or confidential material and are separately filed.

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Attorneys for the Industrial Customers of Idaho Power

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IDAHO PUBLIC UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY TO ESTABLISH ITS BASE LEVEL FOR NET POWER SUPPLY EXPENSES FOR 2010.	)	**CASE NO. IPC-E-10-01** COMMENTS AND PROTEST OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER

Pursuant to Rule 203 of the Rules of Procedure of the Idaho Public Utilities Commission (the "Commission") and the Commission's Notice served January 28, 2010, the Industrial Customers of Idaho Power ("ICIP") hereby file these comments and protest. For the reasons set forth below, ICIP protests Commission approval of Idaho Power Company's ("Idaho Power's" or the "Company's") request for a $74.8 million increase in its base level Net Power Supply Expenses ("NPSE") for 2010 in its Idaho jurisdiction. ICIP respectfully requests that the Commission disallow inclusion of increased costs of surface coal mined from the Company's affiliate coal mine for its Jim Bridger coal plant. Additionally, with regard to affiliate relationships, ICIP respectfully requests the Commission issue an order (1) requiring Idaho Power to seek prior approval of contracts with, and price increases for supplies provided by, the utility's affiliate companies, and (2) requiring that such affiliate sales be recorded in the Company's accounts at the lesser of the affiliate's cost or the market rate. ICIP also respectfully requests that the Commission require Idaho Power to account for projected decreases in energy costs that the Company should achieve with its DSM programs during the NPSE test period. Finally, ICIP respectfully requests that the Commission disallow inclusion in the base level NPSE of increased expenses related to PURPA contracts not yet online and the expected Hoku Materials, Inc. ("Hoku") load not yet online.

BACKGROUND

Idaho Power requests that the Commission issue an Order approving an increase in the Company's base level of NPSE, which the Company would use prospectively to set both base rates effective June 1, 2010, and for use in the 2010 through 2011 Power Cost Adjustment ("PCA") calculations. The Commission typically "determines the normal or expected annual power supply costs for Idaho Power in a general rate case and incorporates recovery of those costs in base rates. Actual power supply costs that vary from the normal amount included in rates are captured each year through the Company's [PCA]." *In the Matter of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to its Customers in the State of Idaho*, Case No. IPC-E-08-10, Order No. 30722, p. 19 (January 30, 2009).

Under the PCA mechanism in a poor water year, however, the Commission requires "the Company's shareholders pay 5% of the costs that exceed power costs recovered through base rates to provide incentive to the Company to make only prudent power cost decisions." *In the Matter of the Application of Idaho Power Company for Authority to Implement Power Cost Adjustment (PCA) Rates for Electric Service from June 1, 2009 through May 31*, Case No. IPC-E-09-11, Order No. 30828, p. 10 (May 29, 2009). Conversely, in a good water year, the

Commission requires Idaho Power to credit its ratepayers with 95% of the below normal cost savings. *See id.* at p. 1. Thus, miscalculations one way or the other in the base level NPSE will result in the utility or the ratepayers losing the ability to recover costs or savings to which they would otherwise be entitled.

The Commission set the Company's currently authorized base level NPSE in the Company's 2008 general rate case. *See* Order No. 30722 at pp. 19-21. There, the Company sought approval of a base level NPSE of $91,472,564, but the Commission only approved a base level NPSE of $80,243,253. *Id.* Subsequently, the Company and several parties entered into, and the Commission approved, a settlement stipulation in a docket regarding amortization of tax credits, wherein the Company agreed not file a general rate case to become effective prior to January 1, 2012. *See In the Matter of Idaho Power Company for an Order to Amortize Additional Accumulated Deferral Income Tax Credit and Approving a Rate Case Moratorium*, Case No. IPC-E-09-30, Order No. 30978 (January 13, 2010). As part of that stipulation, the parties also agreed to "make a good faith effort to reach agreement on the maximum change of the base level for net power supply expenses and submit any agreement to the Commission for approval." *Application, In the Matter of Idaho Power Company for an Order to Amortize Additional Accumulated Deferral Income Tax Credit and Approving a Rate Case Moratorium*, Case No. IPC-E-09-30, Attachment 1, ¶ 7.1 (November 9, 2009).

On January 19, 2010, the Company filed its application to set the base level NPSE for 2010. *Application, In the Matter of the Application of Idaho Power Company to Establish its Base Level for Net Power Supply Expenses for 2010* (hereinafter "*Application*"), Case No. IPC-E-10-01 (January 19, 2010). The Company's filing asserts that the difference between the base level NPSE authorized in the 2008 general rate case and that for the 2010 is $78.4 million system-wide, and $74.8 million on an Idaho jurisdictional basis. *Application*, at ¶ 4. The filing submits that increases in payments to PURPA facilities, increased coal costs for the Company's three coal-fired power plants, and reduced revenues from surplus sales due to decreased gas prices are the principal drivers of this $74.8 million increase. *Id.* at ¶ 5. The Company states, however, that these "expenses are also affected by" a decrease in load during the 2010 test period from 15.9 million MWhs to 15.7 MWhs, which would presumably decrease the base level of NPSE.

On February 2, 2010, shortly after the Company's initial filing, ICIP filed its petition to intervene, and commenced discovery in an effort to reach an agreement on the base level for NPSE in 2010 pursuant to the stipulation in Case No. IPC-E-09-30. Then, on March 2, 2010, the parties who had intervened at that time convened a settlement conference, but were unable to reach an agreement. ICIP therefore respectfully submits these comments and protest to the Company's filing for approval of a $74.8 million increase in its currently authorized base level NPSE.

DISCUSSION

A. The Commission should disallow increases in affiliate surface coal cost and should issue orders requiring procedures that will ensure fair affiliate transactions in the future.

Idaho Power seeks to include a huge increase in its coal costs to its Jim Bridger Coal plant ("Bridger") in this 2010 NPSE.[1] The increased cost of coal at Bridger has resulted in an

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[1] The prudency of this expense is also an issue in Idaho Power's ongoing Oregon energy cost update docket -- Public Utility Commission of Oregon Docket UE 214. Because of the unavailability earlier of certain items produced in discovery in this Idaho NPSE case, these comments will cite and refer to testimony and discovery provided in the Oregon docket, to the extent it is not subject to the protective order in the Oregon docket. The redacted versions of the Oregon Commission Staff's testimony and exhibits relevant to the Bridger coal issue are Exhibit 1 to these comments.

increase fuel cost at the plant from $16.12 per MWh to $21.29 per MWh. Direct Testimony of Scott Wright, Idaho Power Company, Case No. IPC-E-10-01, at p. 8 (January 20, 2010).

Idaho Power and PacifiCorp currently supply about one-third of Bridger's coal needs from a third-party mine, the Black Butte Coal mine. Exhibit 1, at p. 9. The utilities have supplied the remainder of Bridger's needs with coal from the Bridger Coal Company ("BCC"). Idaho Power's subsidiary, Idaho Energy Resources Company ("IERCO"), owns 33.33% of that mine, with PacifiCorp's subsidiary, Pacific Minerals, Inc.. Exhibit 1, at p. 6. BCC is therefore an affiliate of Idaho Power. *Id.* For rate making purposes, Idaho Power treats the mining costs at BCC like any other regulated expense for which it earns a rate of return. The "sales price" for the BCC coal used in this NPSE docket "includes an operating margin, equal to the overall rate of return authorized in general rate cases where IERCO/BCC operations are treated as part of the regulated activities of the Company." Exhibit 2. Idaho Power adjusts the sales price "periodically as updated BCC mining expense data becomes available." *Id.*

So although there is little risk of true cross subsidization with this affiliate relationship, Idaho Power and PacifiCorp have been a operating captive mine for a long period of time rather than purchasing the coal on the open market. Further, unlike coal Idaho Power purchases from third parties, Idaho Power earns a return on its investment and operations at BCC, and thus has embedded incentives to continue operating the captive mine. The Commission should pay close attention to this affiliate relationship because free-market forces do not regulate the price of coal from the affiliate mine.

REDACTED VERSION – The redacted portions of this document allegedly contain trade secrets or confidential material and are separately filed.

1. The Commission should not approve the Company's request for increased cost for coal supplied to the Jim Bridger Plant from its affiliate mining company.

BCC coal includes both surface-mined and underground-mined coal. Idaho Power stated in discovery in this case that of the [redacted] tons of coal consumed at Bridger annually, [redacted] tons come from the Black Butte Mine. Idaho Power's White Paper, at p. 2.[2] The Company projects that the BCC surface coal deliveries will be [redacted] tons in 2010 and [redacted] tons in 2011, and the underground BCC coal deliveries will be [redacted] tons and [redacted] tons in 2010 and 2011, respectively. *Id.* Because of required changes in mining and accounting, the price of BCC surface-mined coal increased substantially at the conclusion of 2009. *See* Exhibit 1, at pp. 39-41.

According to Idaho Power's discovery responses, the average cost of surface and underground BCC coal, not including Idaho Power's "operating margin," or added profit, is [redacted] in 2010, Exhibit 3, at p. 4, and ICIP calculates the average "sales price" including the operating margin to be [redacted], Exhibit 3, at p. 2. In contrast, Idaho Power will only pay [redacted] per ton for Black Butte coal (presumably including Black Butte's profit margin). Exhibit 3, at p. 4. Inexplicably, however, Idaho Power apparently used an even higher BCC sales price of [redacted] per ton and a cost of [redacted] per ton for Black Butte coal in its AURORA run for this NPSE filing. *See* Exhibit 4. Absent a convincing explanation, that difference alone is grounds for a disallowance of some of Idaho Power's requested base level NPSE for Bridger coal costs.

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2 References to Idaho Power's White Paper refer to the confidential document Idaho Power provided in response to Idaho Commission Staff's Production Request 4. Because ICIP expects Idaho Power to provide the White Paper to the Commission, ICIP does not include it as an exhibit to these comments.

Nevertheless, the high cost of BCC coal appears to be attributable to the surface-mined coal, which according ICIP's calculation of data provided in discovery will average [redacted] per ton in 2010, and will be as high as [redacted] per ton in one month. Exhibit 3, at p. 2. And those costs Idaho Power provided for the surface-mined coal exclude Idaho Power's operating margin which it will charge ratepayers.

In Oregon Commission Docket UE 214, the Oregon Commission Staff calculated that replacing the BCC surface-mined coal with the coal from Black Butte Mine for Oregon's 2010 energy cost update test year (April 2010 to March 2011) would result in a system-wide savings of about $15.6 million, only $723,110 of which is attributable to Oregon. Exhibit 1, at p. 12. Oregon Commission Staff proposed disallowing this amount in its testimony, and argues replacing BCC surface coal with Black Butte coal is feasible based on the information Idaho Power supplied in that docket. Exhibit 1, at p. 16.

Late last week, Idaho Power provided responses to discovery requests in this Idaho case from Idaho Commission Staff and ICIP, including a confidential white paper disputing the conclusions reached by the Oregon Commission Staff regarding the availability and usefulness of Black Butte coal. ICIP's counsel and expert received the confidential portions of this latest round of discovery last Friday, March 4, 2010 – hardly enough time to fully analyze this complex issue. Idaho Power primarily defends its continued use of surface-mined BCC coal on the grounds that the Black Butte coal is either an unavailable replacement or of an unsuitable quality given the required coal quality and coal blending metrics required by the Bridger plant.

But even Idaho Power's own white paper indicates that at least some additional Black Butte coal appears to be available. Idaho Power admits that as of communications [redacted]

[redacted]. Idaho Power's White Paper, at p. 8. [redacted] *Id.* (emphasis added). [redacted].

In sum, Idaho Power's white paper and its discovery responses have raised as many questions as they have answered. Although ICIP cannot speak for Staff or the Idaho Irrigation Pumpers Association, ICIP is skeptical that anyone could fully analyze this issue prior to the filing deadline for these comments. At this time, therefore, as far as ICIP is aware, nobody but Idaho Power and PacifiCorp has fully analyzed whether it is prudent for the utilities to continue supplying Bridger with large quantities of their surface-mined, affiliate coal.

Nevertheless, it is highly likely that there is a cheaper alternative to continuing to use the now-very-costly, surface-mined coal from BCC. This is not an arm's length negotiation for the purchase of coal from a mine independent from Idaho Power and PacifiCorp. Idaho Power asserts in its white paper that [redacted] Idaho Power's White Paper, at p. 9. But this overlooks that Idaho Power has incentive to continue and expand mining operations at BCC because – unlike the third party Black Butte Mine – the Company earns a return on its investments and operations at BCC. Thus, the utility should have a higher burden to prove the prudency of the affiliate costs and operating margins it charges its ratepayers than it would have when simply buying necessary supplies on the open market. Here, however, the Company has not provided adequate information in a timely fashion for the Commission and interested parties to fully consider and vet this issue.

Thus, ICIP respectfully requests that the Commission disallow these increased costs for surface-mined BCC coal from the base level NPSE until the issue is fully analyzed. In addition, the Commission should require the Company to prove that there is no market for additional coal, or on a long-term basis that their affiliate surface-mined coal is cheaper than the market. The Commission could do so by expanding this docket to further investigate the issue. Or the Commission could disallow the increased Bridger coal costs from the base level NPSE in this case and require Idaho Power to prove them to be prudently included expenses in its forecasted expenses exceeding the base level NPSE in the upcoming PCA case. If the Company is able to do so, it may recover its costs through the PCA.

2. Disallowing the increased surface-mined BCC coal expenses in this NPSE filing cannot constitute a taking of Idaho Power's property.

The Commission should reject any argument that disallowing the increased cost of surface-mined affiliate coal from its base level NPSE for 2010 and requiring the Company to prove them to be prudently incurred in the upcoming PCA docket would constitute a taking. As mentioned above, Idaho Power's PCA mechanism only allows for the Company or the ratepayers to recover 95% of energy costs that vary from the base level of NPSE. The Company could lose the ability to recover 5% of the increased surface-mined BCC coal costs disallowed from the base level NPSE even if it later proves those continued operations to be prudently incurred in the upcoming PCA docket. So one could argue that, to avoid a taking, the Commission should allow the increased BCC surface-mined coal expenses into the base level NPSE in this docket and then analyze the issue in detail in the upcoming PCA.

No taking will occur here, however. The U.S. Constitution provides that private property shall not be taken for public use without just compensation. United States Constitution Amendment V. The Fifth Amendment is made applicable to the states through the Fourteenth Amendment. *Texaco, Inc. v. Short,* 454 U.S. 516, 523 n. 11 (1982). The Idaho Constitution provides that "[p]rivate property may be taken for public use, but not until a just compensation, to be ascertained in the manner prescribed by law, shall be paid therefor." Idaho Constitution Article I, § 14. With regard to ratemaking, "[t]he Constitution protects utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory." *Hayden Pines Water Co. v. Idaho Public Utilities Commission*, 122 Idaho 356, 358, 834 P.2d 873, 875 (1992) (internal quotation omitted).

Idaho Power is a regulated monopoly with the burden to timely prove the prudency of the investments on which it intends to earn a return from its ratepayers. Idaho Power's opening testimony in this docket does little to explain the prudency of the increased coal costs overall, and does not even distinguish between increased costs at BCC for surface versus underground coal. *See* Direct Testimony of Scott Wright, at pp. 8-9. Determining the increase to be largely attributable to increased costs for affiliate, surface-mined coal required extensive additional time to obtain and review materials in discovery. When a regulated utility provides inadequate information regarding the prudency of the costs of its operations, a limited disallowance of recovery of those costs that results from the utility's own delay is not "so 'unjust' as to be confiscatory." *Hayden Pines Water Co.*, 122 Idaho at 358.

Further, based on the information provided so far, it seems equally likely that the Commission could determine that continued operation of some or all of the surface mining at BCC is imprudent. If the Commission allows these costs into the base level NPSE for 2010 and then determines after June 1, 2010 that they are not prudent expenses, ratepayers would lose the ability to ever recover a refund of 5% of the imprudent costs incurred after June 1 through a future PCA. Requiring ratepayers to pay Idaho Power 5% of those imprudent costs by allowing them into the base level NPSE in this docket would be patently unjust. The Company bears the burden to prove prudency. The Company has not met that burden in a timely fashion, and delaying a disallowance of these expenses for fear of a "taking" will expose ratepayers to the risk of losing the ability to ever obtain a full refund of amounts imprudently spent on affiliate coal.

3. The Commission should issue an order requiring Idaho Power to seek prior approval of contracts with, and price increases for supplies provided by, the Company's affiliates.

This case demonstrates why the Commission should require Idaho Power to file for pre-approval of increases in costs for supplies provided by an affiliate. When there is not an arm's length relationship between the utility and its supplier, the utility should have a heightened burden to prove the prudency of the costs. And the utility should obtain pre-approval of increases in such costs so that the Commission and the interested parties have an adequate opportunity to fully analyze the issue with all necessary information. Such a pre-approval process would prevent a situation as exists here -- where the utility seeks an almost immediate approval of a massive increase in costs from an affiliate supplier.

4. Additionally, the Commission should issue an order that, when Idaho Power's affiliate sells services or supplies to Idaho Power, the sales shall be recorded in the utility's accounts at the affiliate's cost or the market rate, whichever is lower.

Idaho has no official policy on how to charge ratepayers for a utility's affiliate-provided expenses. Because market forces do not regulate the transaction, the Commission should require that affiliate costs be recorded in the Company's accounts at the affiliate's cost or the market rate, whichever is lower. ICIP respectfully requests that the Commission issue an order making this the official policy in Idaho. The Commission has the authority to issue such an order and doing so would clarify the law in this state.

B. The Commission should require the Company to include the reductions in demand it expects to achieve with its demand side management programs in its AURORA runs calculating the base level NPSE.

Idaho Power's testimony in this docket does not state that the Company has factored in the additional demand and peak reductions it expects to achieve through its demand side reduction ("DSM") programs in 2010 when calculating the base level of NPSE for 2010 The Company therefore appears to assume there will be no additional reductions in overall load or in peak load from its DSM programs that will impact the cost of power supply. In addition, if there are reductions in the 2010 energy costs from the operation of the DSM programs, the ratepayers would presumably have to rely on the PCA to refund to them only 95% of those savings.

The Company should account for anticipated DSM achievements when calculating its base level NPSE. Idaho Power currently collects an energy efficiency rider of 4.75% of base rates, which Idaho Power projected will amount to over $33 million in 2010. *See* Direct Testimony of Tim Tatum, Idaho Power, Exhibit No. 3, Case No. IPC-E-09-05 (March 16, 2009). The Company calculates very detailed projections for how much overall load reduction the Company will achieve and how much peak reduction it expects to achieve through the DSM programs. *See, e.g., Idaho Power Company 2009 Integrated Resource Plan,* Case No. IPC-E-09-33, pp. 41-47 (December 28, 2009) (projecting DSM savings in future years). The Commission should require the Company to calculate and use DSM projections, including the benefits of shifting load off of peak hours, in its model runs for its base level NPSE test year. Doing so would provide incentive for the Company to actually achieve the demand and peak reductions it projects to be achievable. On the other hand, failure to account for all projected energy cost savings from DSM achievements in the base level NPSE calculations will force ratepayers to finance DSM programs without allowing them to recognize the full benefit of those programs.

C. The Commission should not approve the Company's request to be compensated for increased energy costs it expects to pay PURPA projects under contracts not yet supplying power to Idaho Power, or for the projected Hoku load that is not yet online.

Idaho Power should not charge ratepayers for energy costs for which it is incurring no expense. If a power project or new load is under contract to come online during the test period, the Company should not include that load and its revenues in the base level NPSE for the test period unless the Company is reasonably certain the project or load will come online at the time the Company forecasts it to come online in AURORA runs calculating NPSE.

1. Eleven PURPA Projects are not yet online.

Although there are several PURPA projects scheduled to come online in 2010 pursuant to recently executed contracts, ratepayers should not compensate the utility for the expected payments the utility will make under those contracts until the projects are actually delivering power to the utility for ratepayer use. The Company has included 169 aMW of PURPA generation the 2010 test year. Direct Testimony of Scott Wright, at p. 13. This is an increase of 42 aMW and $24.5 million in PURPA expense. According to Idaho Power's Response to Commission Staff's Production Request 2, these amounts include 11 projects for which the

Company has signed contracts but are not currently on-line. Although ICIP has not had access to AURORA in this case, Staff has indicated that running AURORA without these 11 new PURPA contracts reduces the base level NPSE by over $7 million. Because PURPA expenses are not subject to the PCA's 95% limitation on cost recovery, removing these anticipated PURPA expenses from the base level NPSE will not expose the Company to any loss when they are subsequently included a PCA to account for exact date when they came online.

2. The Hoku load is not yet online.

Likewise, ratepayers should not pay for increased energy costs associated with the expected new load from Hoku, which signed a contract to begin service in December 2009. *See* Direct Testimony of Scott Wright, at p. 7. Hoku has not yet taken such service, and the Company provides no evidence that it will do so during the 2010 test year. Yet the Company included $15.77 million in revenues from the first block of that Hoku contract in this filing. *See id.* at Exhibit 1, p.1. Although ICIP has not had access to AURORA in this case, Staff has indicated that running AURORA without the Hoku load results in a decrease in base level NPSE of almost $4 million.[3]

CONCLUSION

ICIP protests Commission approval of Idaho Power's request for an increase of $74.8 million in base level NPSE for 2010 in the Idaho jurisdiction. ICIP respectfully requests that the Commission disallow inclusion of the increased costs of surface-mined coal from the Company's

[3] Although Staff provided ICIP with the impact to base level NPSE from removal of all increased energy costs at Bridger, the 11 PURPA contracts, and the Hoku load, ICIP received no such calculations of the rate impact of surface-mined BCC coal alone, such as those provided in the Oregon Commission Staff's testimony for the test period in the Oregon docket. Assuming no other parties will provide such a dollar figure in their comments, this lack of information further underscores the need to further examine the Bridger issue or to issue an order requiring procedures that will prevent such a lack of knowledge in future cases.

affiliate coal mine for its Jim Bridger coal plant in the base level NPSE. Additionally, with regard to affiliate relationships, ICIP respectfully requests the Commission issue an order (1) requiring Idaho Power to seek prior approval of contracts with, and price increases for supplies provided by, the utility's affiliate companies, and (2) requiring that such affiliate sales be recorded in the utility's accounts at the lesser of the affiliate's cost or the market rate. ICIP respectfully requests also that the Commission require Idaho Power to account for projected decreases in energy costs that the Company should achieve with its DSM programs during the NPSE test period. Finally, ICIP respectfully requests that the Commission disallow inclusion of energy costs related to PURPA contracts not yet online and the expected Hoku load not yet online.

Respectfully submitted this 11th day of March 2010,

Greg Adams
RICHARDSON & O'LEARY, PLLC

PUBLIC UTILITIES COMMISSION

OF IDAHO

CASE NO. 1PC-E-10-01

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UTILITIES COMMISSION

COMMENTS AND PROTEST OF

INUDSTRIAL CUSTOMERS OF IDAHO POWER

EXHIBIT 1

REDACTED TESTIMONY AND EXHIBITS OF OREGON PUBLIC

UTILITY COMMISSION STAFF TESTIMONY IN OREGON

COMMISSION DOCKET UE 214

MARCH 11, 2010

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

OPENING TESTIMONY

January 20, 2010

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 200

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09 - 418. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 214 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Michael Dougherty. I am the Program Manager for the Corporate Analysis and Water Regulation Section of the Public Utility Commission of Oregon (Commission). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I describe my adjustments to Idaho Power Company's (Idaho Power) power supply costs concerning its three coal plants: Bridger, Boardman, and Valmy as listed in Idaho Power/101, Wright/1.

Q. HAVE YOU PREPARED ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared:

Confidential Exhibit Staff/202, consisting of 2 pages;

Exhibit Staff/203, consisting of 21 pages; and

Confidential Exhibit Staff/204, consisting of 2 pages.

Q. PLEASE PROVIDE A SUMMARY OF YOUR ADJUSTMENTS.

A. The following table summarizes my adjustments to Idaho Power's power supply costs concerning its three coal plants: Bridger, Boardman, and Valmy as listed in Idaho Power/101, Wright/1.

Table 1 – Summary of Staff Adjustments

Plant	Exhibit Idaho Power/101, Wright/1	Staff	Adjustment
Bridger	$105,249,100	$89,664,839	$15,584,261
Boardman	$6,773,800	$6,773,800	$0
Valmy	$50,266,500	$50,266,500	$0
Total Adjustment			$15,584,261
Total Oregon Adjustment (.0464 allocation)			**$723,110**

Q. PLEASE SUMMARIZE THE ANALYSES SUPPORTING YOUR RECOMMENDED ADJUSTMENTS.

A. Bridger– Because Bridger receives coal from an affiliated interest coal mine; I performed several lower-of-cost-or-market (LCM) analyses pursuant to Oregon Administrative Rule (OAR) 860-027-0048, *Allocation of Costs by an Energy Utility*. The primary LCM analysis results in an Oregon adjustment of $723,110 to the Idaho Power's Bridger power supply costs.

Boardman and Valmy – These coal plants are supplied by third party mines. I examined the costs per ton of coal and the tons of coal delivered. As a result of my analysis, I do not have any adjustments to the Boardman and Valmy power supply costs.

Q. DO YOU PROVIDE ALTERNATIVE RECOMMENDATIONS FOR THE COMMISSION TO CONSIDER?

A. Yes. Concerning coal costs from affiliate, Bridger Coal Company (BCC) supplied to Bridger, I performed four LCM analyses. My primary analysis, as shown in the above table, results in an Oregon adjustment of $723,110 for Bridger power supply costs. A first alternative analysis results in an Oregon adjustment of $691,354 for Bridger power supply costs. I also performed a second and third alternative analysis that I did not use as recommended adjustments. These analyses are explained later in testimony and are shown in Staff Confidential Exhibit/202, Dougherty/1-2. The following table shows the power supply costs adjustments based on two LCM analyses concerning BCC.

Table 2 – Alternative Recommended Oregon Adjustments

Primary Adjustment	$723,110
Alternative Adjustment	$691,354

Q. DOES THE COMMISSION HAVE A TRANSFER PRICING POLICY CONCERNING TRANSACTIONS BETWEEN A UTILITY AND ITS AFFILIATED INTERESTS?

A. Yes. OAR 860-027-0048, *Allocation of Costs by an Energy Utility*, sets forth the Commission's Transfer Pricing Policy. Section (4)(e) of the rule states:

> When services or supplies (except for generation) are sold to an energy utility by an affiliate, sales shall be recorded in the energy utility's accounts at the approved rate if an applicable rate is on file with the Commission or with FERC. If services or supplies (except for generation) are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's

> accounts at the affiliate's cost or the market rate, whichever is lower.

Under the rule, supplies that are not under an approved rate shall be recorded in the energy utility's accounts at the lower of the affiliate's cost or market rate. BCC is an affiliate of Idaho Power. As a result, this transfer pricing rule is relevant concerning pricing of coal supplied from BCC to Bridger.

Q. PLEASE EXPLAIN THE AFFILIATED RELATIONSHIP BETWEEN IDAHO POWER AND BCC.

A. According to Idaho Power s 2008 Affiliated Interest Report, Idaho Energy Resources Co. (IERCO) is a regulated subsidiary of Idaho Power in all jurisdictions including Oregon. IERCO owns 33.33 percent of BCC, the coal mining joint venture with Pacific Minerals Inc (PMI),[1] which is a subsidiary of PacifiCorp. The Commission approved a coal supply agreement between IERCO and Idaho Power in Commission Order No. 91-567 (UI 107), dated April 25, 1991.

Q. PLEASE DISCUSS BCC'S OPERATIONS AND COSTS.

A. BCC's overall costs are a weighted cost of surface mining operations and underground mining operations. The average BCC cost per ton for the April 2010 to March 2011 timeframe is [redacted].

Q DID COMMISSION ORDER NO. 91-567 (UI 107) RESERVE THE RIGHT TO REVIEW FOR REASONABLENESS ALL FINANCIAL ASPECTS CONCERNING PRICING OF COAL FROM BCC?

A. Yes. The Commission Order states:

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[1] PMI owns the remaining 66.67 percent of BCC.

> The transfer price for the coal which is provided to Bridger to Idaho shall be billed at actual cost. Cost in this case is equivalent to market for the services. Since all of IERCO's results of operations are merged with and made part of Idaho's for ratemaking, there is no possibility of cross-subsidization.[2]

The order also states on page 5:

> The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any subsequent rate proceeding.[3]

Q. IF THE ORDER INDICATES THAT COST IN THIS CASE IS EQUIVALENT TO MARKET AND THAT THERE IS NO POSSIBILITY OF CROSS-SUBSIDIZATION, WHY DO YOU RECOMMEND AN ADJUSTMENT?

A. I made an adjustment because BCC's costs are higher than the current market cost. Staff's memo in UI 189, Commission Order No. 01-472 (PacifiCorp's affiliated interest agreement with PMI) provides a description concerning the historical costs of BCC and states:

> The company (*PacifiCorp*) states that BCC coal provides it with advantages such as a consistently reliable coal source and a minimization of fuel transportation and handling costs. Historically, from 1990 through 1999, the average cost of coal provided by the Coal Supply Agreement ranged from $3 to $9 per ton less than the average market price of Southern Wyoming coal delivered to the plant.[4]

However, after calculating four LCM analyses, my review indicates that BCC's costs are no longer below market costs for the Green River Basin (GRB) in Southern Wyoming. Therefore, there was a substantial change in costs that results in BCC's cost being higher than market. Although there is no cross-

[2] Commission Order 91-567 (UI 105), at 4. *See* Exhibit Staff/203, pages 1 – 5.
[3] Id, at 5. *See* Exhibit Staff/203.
[4] Commission Order No. 01-472 (UI 189). Appendix A, page 2. *See* Exhibit Staff/203, page 9.

subsidization between IERCO and Idaho Power, customers are paying a higher cost for coal being delivered by BCC to Bridger than the "market" (Black Butte Mine) cost of coal, which is also delivered to Bridger.

Q. IN UE 207, PACIFICORP STATED IN PPL (TAM)/200, LASICH/6[5] THAT THERE IS NO ADDITIONAL (COAL) CAPACITY IN THE AREA TO SUPPLY THE BRIDGER PLANT. IN LIGHT OF THIS TESTIMONY, SHOULD THE COMMISSION STILL CONSIDER USING THE TRANSFER PRICING POLICY CONCERNING IDAHO POWER AND BCC?

A. Yes. OAR 860-027-0048 applies to pricing and a market. Based on information provided by Idaho Power in confidential responses to Staff's Data Requests Nos. 1 and 2,[6] there is a market and pricing for coal in the GRB. Idaho Power uses this market supplied coal for approximately one-third of the coal utilized by Bridger. Therefore, the Commission should use the LCM standard pursuant to OAR 860-027-0048. The rule defines market rate as (emphasis added):

> "the ***lowest*** price that is ***available*** from nonaffiliated suppliers for comparable services or supplies."[7]

1. Lowest Price – Because Idaho Power receives coal from a third-party mine to supply Bridger, there is adequate data, which clearly shows there is a lower nonaffiliated price for coal in the Green River Basin (GRB) area of Wyoming. The nonaffiliated Black Butte Mine (Black Butte) average

[5] Included in Exhibit Staff 203, page 13.
[6] Included in Confidential Exhibit Staff 204.
[7] OAR 860-027-0048(1)(i).

delivered coal prices for coal supplied to Bridger [redacted] is significantly lower than the BCC mine delivered coal costs to Bridger at [redacted].[8]

2. Availability – The fact that nonaffiliated Black Butte supplies approximately one-third of Bridger clearly demonstrates that a nonaffiliated supply is available. Additionally, Commission Order No. 79-754, page 17, refers to the PacifiCorp's position on third-party availability in the GRB and states (emphasis added):

> "(2) Unlike the telephone affiliates, an ***alternate market exists for coal sold to PP&L*** at a price higher than the price charged PP&L ratepayers."[9]

Q. HAS IDAHO POWER DISCUSSED COST DRIVERS CONCERNING BCC COAL?

A. Yes, but Idaho Power focuses on long-term coal supplies that expired at the end of 2009.[10] In contrast, PacifiCorp explained certain changes in BCC's costs in PPL (TAM)/200, Lasich/4 and 5 (UE 207) by stating:

> For many years, BCC was able to extract coal at the Bridger surface mine using low-cost highwall mining. The mine has now reached the stage, however, where BCC has replaced this production method with higher-cost dragline mining to properly steward the resources of the mine. Additionally, current accounting pronouncement EITF04-6 requires that production costs be assigned only to extracted coal, not coal that is uncovered but remains in the pit. This contributes to higher costs in 2010 because more coal is scheduled to be uncovered than will be extracted; the opposite will be true in a year when previously uncovered coal is ultimately extracted.[11]

[8] Staff notes that in PacifiCorp's UI 189 application, PacifiCorp on page 5, footnote 2, specifically stated that BCC and Black Butte "are of comparable quality." See Exhibit Staff/203, page 14.
[9] Included in Staff Exhibit/203, page 15.
[10] Idaho Power/100, Wright/1.
[11] Included in Exhibit Staff/203, pages 16 and 17.

As can be seen from the above statement, one of the cost drivers is an accounting requirement concerning extracted coal that BCC (and other mines) must comply with. As an example of the effect of the accounting requirement, PacifiCorp stated in UE 207 that PacifiCorp's 2010 test period cost of BCC would be approximately $30.63 per ton without EITF 04-6 as compared to $33.54 per ton with EITF 04-6. [12]

Q. PLEASE LIST THE LCM ANALYSES THAT YOU PERFORMED.

A. Because I had concerns with the level of certain cost components embedded in the BCC's weighted costs, I performed four analyses as follows. These analyses are explained in greater detail later in testimony.

1. <u>Primary Analysis</u> – Replaced BCC surface operations costs with market (Black Butte) average (spot, deferred, and transportation) costs and maintained the BCC underground costs to achieve a total BCC cost for ratemaking purposes.

2. <u>First Alternative Analysis</u> - Replaced BCC surface operations costs with market (Black Butte) spot and transportation costs (removed lower cost deferred tonnage) and maintained the BCC underground costs to achieve a total BCC cost for ratemaking purposes.

3. <u>Second Alternative Analysis (not recommended)</u> - Replaced BCC surface operations costs with BCC underground costs and maintained the BCC underground costs to achieve a total BCC cost for ratemaking purposes. This resulted in all of BCC's costs being determined by the cost of underground operations.

4. <u>Third Alternative Analysis (not recommended)</u> – Set BCC costs at the market (Black Butte) average (spot, deferred, and transportation) costs for both surface and underground operations to achieve a total BCC cost for ratemaking purposes.

[12] Included in Exhibit Staff/203, page 18.

Q. PLEASE EXPLAIN YOUR PRIMARY LCM ANALYSIS.

A. In my primary market analysis, I used the actual BCC underground mining operations tons and cost and replaced the BCC surface mining operations costs with the average Black Butte cost (spot coal, deferred coal, and transportation)[13] for each month April 2010 to March 2011.[14] I used the average cost to allow customers to achieve the benefits of the deferred coal. The deferred coal represents the contract price of $11.07 per ton for coal to be delivered in 2010 from the Black Butte mine (stand-alone price per ton). The tonnage to be delivered in 2010 was deferred or delayed from prior years, either because of decreased coal requirements at Bridger or force majeure events.[15] Black Butte coal is an excellent market proxy for BCC's surface operations because:

- Black Butte will provide [redacted] thousand tons of coal (Idaho Power's share) to the Bridger coal plant in the April 2010 to March 2011 timeframe;
- Black Butte coal also accounts for approximately one-third of the coal burned by Bridger; and
- Black Butte is also a surface operation mining operation and is of comparable quality to BCC surface coal.

I used the underground mining operations in this analysis because it is an essential part of BCC's operations, comprising approximately [redacted] percent of

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[13] "Spot" refers to the contract price.
[14] Surface coal was not utilized in all twelve months. As such, I only substituted the monthly Black Butte costs during the months surface coal was used at Bridger. *See* Confidential Exhibit Staff/202.
[15] Idaho Power's response to Staff Data Request No. 20. Included in Exhibit Staff/203, page 19.

coal produced by BCC. Because Idaho Power did not provide a breakdown between tons supplied by both the surface and underground operations, I used the ratio ([redacted] percent) of surface coal provided in PacifiCorp's UE 207 filing. This is a reasonable approach because Bridger is jointly operated by PacifiCorp and Idaho Power. As a result of using the market proxy for BCC's surface operations and including the costs of the underground operations, I calculated a $15,584,261 (system-wide) adjustment to Bridger power supply costs as highlighted in the following table. The complete calculation is shown in Confidential Exhibit Staff/203, Dougherty/1.

Table 3 – Recommended Bridger Power Cost Supply Expense

Coal Source	**Cost**
Adjusted BCC Price	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Power Cost Supply	**$89,664,839**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
Adjustment - LCM	**$15,584,261**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $723,110.

Q. PLEASE SUMMARIZE WHY YOUR PRIMARY RECOMMENDATION SHOULD BE ACCEPTED BY THE COMMISSION.

A. The Commission should accept my primary recommendation because:

1. The transfer pricing policy pursuant to OAR 860-027-0048 applies to coal supplied by BCC to the Bridger plant since there is a market for coal and pricing is available;

2. The recommendation uses the April 2010 through March 2011 market (Black Butte) cost of coal being supplied to Bridger as a substitute for surface operations; and

3. The recommendation uses BCC's underground costs in order to recognize an underground component of total costs as BCC has both a surface and underground operation.

Q. PLEASE EXPLAIN YOUR FIRST ALTERNATIVE MARKET ANALYSIS.

A. In my first alternative analysis, I follow the same process as the primary market analysis except that I replace the BCC surface operations with Black Butte's spot and transportation costs. This analysis does not utilize the less expensive deferred price. Because the less expensive deferred coal was not used in the first alternative market analysis to reflect the carry-over tonnage, this first alternative recommended Bridger power supply cost adjustment of $14,899,869 is lower than the primary recommended adjustment. The following table highlights the Bridger power supply cost using the BCC underground mining operations and substituting the surface operations with Black Butte's spot and transportation costs. The complete calculation is also shown in Confidential Exhibit Staff/202, Dougherty/1.

Table 4 – First Alternative Market Analysis - Bridger Power Cost Supply Expense

Coal Source	**Cost**
Adjusted BCC Price	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Power Cost Supply	**$90,349,231**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
First Alternative Adjustment - LCM	**$14,899,869**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $691,354. I used this as an alternative and not primary adjustment because customers should receive the benefits of the lower cost of deferred coal.

Q. YOU PREVIOUSLY MENTIONED THAT YOU PERFORMED A SECOND ALTERNATIVE MARKET ANALYSIS THAT YOU DID NOT USE, PLEASE EXPLAIN THIS ANALYSIS.

A. My second alternative market analysis uses the cost of BCC's underground operations. In this analysis, I replaced the BCC surface mining operations with the underground mining operations cost per ton. As previously mentioned, the underground operations comprise approximately [redacted] percent of total BCC coal, making it the primary source of coal being supplied by BCC. Because there are no other underground sources in the GRB, BCC's underground operation is the only pricing available to use as a market price. The complete calculation is also shown in Confidential Exhibit Staff/202, Dougherty/2.

Table 5 – Second Alternative Market Analysis - Bridger Power Cost Supply Expense

Coal Source	**Cost**
Adjusted BCC Price using 100% Underground	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Fuel Burn Expense	**$88,697,476**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
Adjustment – LCM (Not recommended)	**$16,551,624**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $767,995. I used this as an alternative and not primary adjustment because a surface component of costs should be recognized in the weighted costs. While this adjustment is provided for Commission consideration, I do not believe this alternative is reasonable, given that the surface component of costs is not recognized, and thus should not be adopted.

Q. YOU PREVIOUSLY MENTIONED THAT YOU PERFORMED A THIRD ALTERNATIVE MARKET ANALYSIS THAT YOU DID NOT USE, PLEASE EXPLAIN THIS ANALYSIS.

A. In my third alternative market analysis, I substituted the Black Butte coal (spot, deferred, transportation) for all of Bridger's operations including the underground operations. As a result of this lower cost per ton, this analysis would result in a $6,894,461 system-wide adjustment to Idaho Power s Bridger power supply cost. The following table highlights the Bridger power supply cost using third party coal. The complete calculation is also shown in Confidential Exhibit Staff/202, Dougherty/2.

Table 6 – Third Alternative Market Analysis - Bridger Fuel Burn Expense

Coal Source	**Cost**
Adjusted BCC Price	[redacted]
Third Party Coal (Black Butte Mine)	[redacted]
Total Bridger Fuel Burn Expense	**$98,354,639**
Power Cost Supply from Idaho Power/101, Wright/1	$105,249,100
Adjustment – LCM (Not recommended)	**$6,894,461**

Using Idaho Power's allocation Oregon allocation of 0.0464, the Oregon allocated adjustment is $319,903. As previously mentioned, this analysis does not include an underground component. As a result, I did not include this LCM analysis as a recommended cost concerning Bridger power cost supply expense. As previously mentioned, the underground mining operations are an essential part of BCC's operations and the cost of this operation should be reflected in BCC's total costs under any LCM scenario.

Q. IN BOTH THE PRIMARY AND FIRST ALTERNATIVE ANALYSES, YOU ARE SUBSTITUTING ONLY THE COST OF ONE COMPONENT OF BCC'S TOTAL COSTS IN YOUR LCM ANALYSIS. PLEASE EXPLAIN WHY THE COMMISSION SHOULD ACCEPT THIS METHOD.

A. As previously mentioned, the major cost driver of BCC's higher than market cost is the surface operations. The average surface cost of coal for the timeframe is [redacted] as compared to the average underground cost of coal of [redacted]. Although there is a distinct difference between the two costs, my recommendation is an adjustment from ***BCC's weighted costs***. In reviewing data supplied by Idaho Power, surface and underground operations are budgeted (controllable and non-controllable) as separated operations with specific, dedicated costs. As previously mentioned, the underground operations are the primary source of coal being supplied from BCC.

Q. BECAUSE OF THE VARIATION IN BCC SURFACE OPERATIONS COSTS THAT RESULT FROM EITF 04-6, DO YOU BELIEVE THE SURFACE COSTS RELATED TO EITF 04-6 SHOULD BE LEVELIZED OR TREATED

AS A DEFERRAL TO SOFTEN THE ANNUAL VARIATION ON TOTAL COSTS FOR BCC?

A. No. Although EITF 04-06 requires mines to include stripping costs in the cost of coal that is extracted in a given year, the ***ratemaking*** standard for affiliated interest contracts is the LCM pricing policy outlined in OAR 860-027-0048, *Allocation of Costs by an Energy Utility.* As previously noted, PacifiCorp, which is part owner of BCC, claims in UE 207 PPL/201, Lasich/2-3,[16] that the magnitude of the disparity (resulting from EITF 04-6) will fluctuate based on the amount of coal extracted. However, what will not change is the LCM standard that affiliated pricing is determined for ratemaking. The affiliate's cost, no matter how costs are affected by EITF 04-6 (increased or decreased), should always be examined in comparison to market costs. As previously mentioned, other mines contracted by Idaho Power must comply with this accounting requirement; and it is not a unique phenomenon to BCC.

Because the PCAM is an annual filing that includes other changes in power supply costs from year to year, Staff will be able to perform analyses of the affiliated mines' cost and relationship to market on an annual basis. Because BCC's costs will be reviewed in context of the LCM standard on an annual basis, there is no need to levelize these costs or create a regulatory asset balancing account. In any scenario that compares extracted coal to stripped coal, the affiliate's coal costs would still be the starting basis for Staff's recommendation. It is also important to note that customers would only see a

[16] Included in Exhibit Staff/203, pages 20-21.

"benefit" of EITF 04-6 if Idaho Power's costs are lower than market in low cost years.

Q. DID YOU REVIEW SPECIFIC LINE ITEM COSTS FOR BCC?

A. As part of my review, I reviewed the projected 2010 line item costs for BCC. This review resulted in the identification of costs (certain bonus amounts, donations, fine/citations, etc.) that Staff would recommend as adjustments for the parent company (Idaho Power) during a general rate case review. However, as a result of the LCM analyses, I did not make these adjustments, as the LCM analyses resulted in greater adjustments to Bridger costs.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO COAL IDAHO POWER'S COAL POWER SUPPLY COSTS.

A. The following table summarizes my recommended adjustments to Idaho Power's coal power supply costs:

Table 7 – Alternative Recommended Oregon Adjustments

Primary Adjustment	$723,110
Alternative Adjustment	$691,354

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

January 20, 2010

WITNESS QUALIFICATION STATEMENT

NAME:	MICHAEL DOUGHERTY
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Master of Science, Transportation Management, Naval Postgraduate School, Monterey CA Bachelor of Science, Biology and Physical Anthropology, City College of New York
EXPERIENCE:	Employed with the Oregon Public Utility Commission from June 2002 to present, currently serving as the Program Manager, Corporate Analysis and Water Regulation. Also serve as Lead Auditor for the Commission's Audit Program. Performed a five-month job rotation as Deputy Director, Department of Geology and Mineral Industries, March through August 2004. Employed by the Oregon Employment Department as Manager - Budget, Communications, and Public Affairs from September 2000 to June 2002. Employed by Sony Disc Manufacturing, Springfield, Oregon, as Manager - Manufacturing, Manager - Quality Assurance, and Supervisor - Mastering and Manufacturing from April 1995 to September 2000. Retired as a Lieutenant Commander, United States Navy. Qualified naval engineer. Member, National Association of Regulatory Commissioners Staff Sub-Committee on Accounting and Finance.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

<u>REDACTED VERSION</u>
January 20, 2010

STAFF EXHIBIT 202

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09 - 418. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 214 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

CASE: UE 214
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

January 20, 2010

ORDER NO. 91-567
ENTERED APR 25 1991

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UI 107

In the Matter of the Application of IDAHO POWER COMPANY for approval of an agreement for coal sales with Bridger Coal Company, a joint venture consisting of Idaho Energy Resources Company, A Wyoming Corporation, and Pacific Minerals, Inc., A Wyoming Corporation.	)	ORDER

DISPOSITION: GRANTED

On January 22, 1991, Idaho Power Company (Idaho) filed an application with the Public Utility Commission pursuant to ORS Chapter 757 and OAR 860-27-040. Idaho requested approval of certain coal sales agreements between Idaho, PacifiCorp dba Pacific Power & Light Company (Pacific), and Bridger Coal Company (Bridger).

At its April 16, 1991, public meeting, the Commission adopted staff's recommendation that the application be granted.

The Commission makes the following:

FINDINGS OF FACT

Jurisdiction

Idaho is an Idaho corporation, duly qualified to transact business in the state of Oregon. Idaho engages in the generation, purchase, transmission, distribution, and sale of electric energy to the public in the state of Oregon. Idaho Energy Resources Co. (IERCO) is a wholly owned subsidiary of Idaho. IERCO was incorporated under the laws of the state of Wyoming. Pacific Minerals, Inc. (PMI), is a wholly owned subsidiary of Pacific, incorporated under the laws of the state of Wyoming. Bridger is a joint venture consisting of IERCO and PMI.

On September 22, 1969, Pacific and Idaho entered into agreements for the ownership, construction, and operation of a 1,500 MW coal-fired electric power plant in Wyoming, known as the Jim Bridger Project. The ownership agreement provided for the joint ownership of certain leases covering coal deposits located near the Jim Bridger plant. The operation agreement contemplated joint operation of these coal properties.

Idaho and Pacific subsequently agreed that the coal properties, rather than being jointly owned and operated by Pacific and Idaho, would be owned and operated pursuant to a joint venture agreement dated February 1, 1974. The joint venture, known as the Bridger Coal Company, consists of IERCO, owning one-third of Bridger, and Pacific, owning two-thirds. Idaho transferred to IERCO all of its right, title, and interest in these coal leases. IERCO, in turn, transferred its interest to Bridger pursuant to the joint venture agreement. On February 1, 1974, Pacific and Idaho entered into a coal sales agreement wherein Pacific and Idaho agreed to purchase, and Bridger Coal agreed to deliver and sell coal from coal properties located near the Jim Bridger plant. Pursuant to an amendment dated December 14, 1973, Pacific and Idaho agreed to the construction of a fourth 500 MW unit at Jim Bridger. On September 1, 1979, the coal sales agreement was amended to increase the total annual tonnage of coal sales to provide coal for the newly constructed unit. Other amendments to the coal sales agreement were entered into by agreements dated March 7, 1988, and by an agreement dated January 1, 1990.

IERCO is a wholly owned subsidiary of Idaho and is an affiliated interest since Idaho and IERCO have four directors and/or officers in common. Bridger is likewise an affiliated interest of Idaho in that one-third of Bridger is owned by IERCO, Idaho's wholly owned subsidiary, and therefore Bridger is an entity, 5 percent or more of which is owned by Idaho pursuant to ORS 757.015(6).

Idaho had previously understood that IERCO and Bridger were not subject to affiliated interest filing requirements under ORS 757.495 and OAR 860-27-040 inasmuch as all of IERCO's transactions with Idaho have been subject to regulatory scrutiny and IERCO is disregarded as a separate entity for rate-making purposes. However, in recent discussions with Commission staff and the Attorney General's office, Idaho was informed that transactions with IERCO are technically subject to affiliated interest filing requirements, notwithstanding the fact that IERCO operations are included with Idaho's operations for purposes of rate making. Idaho desires to comply fully with the spirit and the letter of affiliated interest filing requirements and makes this application to ensure compliance with ORS 757.495 and OAR 860-27-040.

Separate records and accounts for IERCO are maintained and the operations of IERCO as a joint venturer in Bridger are subject to regulatory review and scrutiny together with those of Idaho during general rate cases. The operations of IERCO are summarized in Idaho's semiannual reports of operations filed with the Public Utility Commission. IERCO's results of operations have been merged, consolidated, and included with Idaho's for the purposes of filing of income tax returns and for rate-making purposes. Therefore, there is no danger of cross-subsidization between Idaho and IERCO, nor is there any danger of Idaho paying in excess of market value to IERCO or its assignees for the coal purchased. Idaho is paying for its coal the same as if IERCO were not even involved in this transaction. Further, the coal sales agreements have and will continue to provide a reliable source of low-cost coal for the operation of the Jim Bridger plant.

Idaho believes that the proposed coal sales agreements are of benefit to its customers and permit the coal to be purchased by Idaho at reasonable prices. The coal sales agreements do not impair Idaho's ability to provide its public utility service.

Idaho proposes that the coal sales agreements be approved in their entirety.

OPINION

The following statutes are applicable to this transaction:

ORS 757.005 defines a public utility as, *inter alia*, an entity which owns, operates, manages, or controls all or part of any plant or equipment in this state for the production, transmission, delivery, or furnishing of heat, light, or power, directly or indirectly to the public. Idaho is a public utility subject to the Public Utility Commission's jurisdiction.

ORS 757.015(5) defines an "affiliated interest" as "every corporation which has two or more officers or two or more directors in common with such public utility." Idaho and IERCO have four officers and/or directors in common; therefore, an "affiliated interest" relationship exists. Likewise, ORS 757.015(6) defines an affiliated interest as . . . "Every corporation and person, five percent or more of which is directly or indirectly owned by a public utility." One-third of Bridger is owned by IERCO, Idaho's wholly owned subsidiary. Therefore, an affiliated interest exists between Idaho and Bridger.

ORS 757.495 provides that no public utility shall contract with an affiliated interest for services without the Commission's approval. The statute was designed to protect utility customers from abuses which may arise from less-than-arm's-length transactions. CP National Corporation, UF 3842, Order No. 82-93 at 2; Portland General Electric Company, UF 3739, Order No. 1-737 at 6. The standard of review is whether the proposed contract is ". . . fair and reasonable and not contrary to the public interest . . ." See ORS 757.495(3).

The application should be granted. The coal sales agreements in question will not harm Idaho's customers because the agreements provide to Idaho a reliable source of low-cost coal for operation of the Jim Bridger plant.

The transfer price for the coal which is provided by Bridger to Idaho shall be billed at actual cost. Cost in this case is equivalent to market for the services. Since all of IERCO's results of operation are merged with and made a part of Idaho's for rate making, there is no possibility of cross-subsidization. The Commission concludes that the agreement is fair and reasonable and not contrary to the public interest.

Idaho's contract with Bridger has and shall continue to be recognized for rate-making purposes. Expenditures made should be charged to accounts in the manner directed by the Federal Energy Regulatory Commission regulations and by the Commission's rules.

CONCLUSIONS OF LAW

1. Idaho is a public utility subject to the jurisdiction of the Public Utility Commission.

2. An affiliated interest relationship exists between both Idaho and IERCO and Idaho and Bridger.

3. The coal sales agreements referred to hereinabove and made a part of the applicant's case are fair and reasonable and not contrary to the public interest.

ORDER

IT IS ORDERED that:

1. The application of Idaho Power Company for approval of its coal sales agreements, dated February 1, 1974, between Pacific Minerals, Inc.; Idaho Power Company; and Bridger Coal Company, as amended, by amendments dated December 14, 1973; September 1, 1979; March 7, 1988; and January 1, 1990, is granted. This approval shall be effective for accounting purposes as of January 1, 1991.

2. Idaho shall provide staff access to all books of account, as well as all documents, data, and records of Idaho and Idaho's affiliated interest which pertain to the transactions between Idaho and its affiliated interests, IERCO, and Bridger Coal Company.

ORDER NO. **91-567**

3. Idaho Power Company shall notify the Commission in advance of any substantive changes to the agreement, including any material changes in any cost. Any changes to the agreement terms which alter the intent and extent of activities under the agreement from those approved herein shall be submitted for approval in an application for supplemental order (or other appropriate format) in this docket.

4. Idaho Power Company has the responsibility of timely notifying the Commission of all management studies and/or analyses, internal or external audit reports, and any related studies or reports pertaining to the services agreement between Idaho, Pacific, and Bridger and shall promptly provide such information to the Commission upon request.

5. The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any subsequent rate proceeding.

6. Idaho shall comply with the annual reporting requirements for affiliated interest transactions.

Made, entered, and effective APR 25 1991.

PUBLIC UTILITY COMMISSION OF OREGON

Nancy Towslee
Commission Secretary

A party may request rehearing or reconsideration of this order within 60 days from the date of service pursuant to ORS 756.561. A party may appeal this order pursuant to ORS 756.580.

01107.ORD

ENTERED JUN 12 2001

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UI 189

In the Matter of the Application of PACIFICORP for Approval of a Coal Supply Agreement with BRIDGER COAL COMPANY.	))))	ORDER

DISPOSITION: APPLICATION APPROVED WITH CONDITIONS

On January 26, 2001, PacifiCorp filed an application with the Public Utility Commission of Oregon (Commission) pursuant to ORS 757.495 and OAR 860-027-0040 requesting approval of its coal supply agreement with Bridger Coal Company (BCC), an Affiliated Interest.

Based on a review of the application and the Commission's records, the Commission finds that the application satisfies applicable statutes and administrative rules. At its Public Meeting on May 22, 2001, the Commission adopted Staff's recommendation to approve the application with certain standard conditions. Staff's recommendation is attached as Appendix A, and is incorporated by reference.

OPINION

Jurisdiction

ORS 757.005 defines a "public utility" as anyone providing heat, light, water or power service to the public in Oregon. The Company is a public utility subject to the Commission's jurisdiction.

Affiliation

An affiliated interest relationship exists under ORS 757.015.

Applicable Law

ORS 757.495 requires public utilities to seek approval of contracts with affiliated interests within 90 days after execution of the contract. The intent of the statute is to protect ratepayers from the abuses which may arise from less than arm's length transactions. *Portland General Electric Company*, UF 3739, Order No. 81-737 at 6. Failure to file within the 90-day time limit may preclude the utility from recovering costs incurred under the contract.
See ORS 757.495.

ORS 757.495(3) requires the Commission to approve the contract if the Commission finds that the contract is fair and reasonable and not contrary to the public interest. However, the Commission need not determine the reasonableness of all the financial aspects of the contract for ratemaking purposes. The Commission may reserve that issue for a subsequent proceeding.

CONCLUSIONS

1. The Company is a public utility subject to the jurisdiction of the Commission.
2. An affiliated interest relationship exists.
3. The agreement is fair, reasonable, and not contrary to the public interest.
4. The application should be granted, with conditions.

ORDER

IT IS ORDERED that the application of PacifiCorp for authority to engage in a Coal Supply Agreement with Bridger Coal Company, is granted, subject to the conditions stated in Appendix A.

Made, entered, and effective ________________________.

BY THE COMMISSION:

____

Vikie Bailey-Goggins
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A party may appeal this order to a court pursuant to ORS 756.580.

ITEM NO.__ Staff/203
Dougherty/8

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MAY 22, 2001

REGULAR AGENDA__ CONSENT AGENDA X EFFECTIVE DATE______

DATE: May 16, 2001

TO: Phil Nyegaard through Marc Hellman and Mike Myers

FROM: Tom Riordan

SUBJECT: UI 189 – PacifiCorp Application for approval of a Coal Supply Agreement with Bridger Coal Company, Inc. (BCC), an Affiliated Interest

SUMMARY RECOMMENDATION:

I recommend approval of the requested agreement with the conditions noted in the detailed recommendation.

DISCUSSION:

Background:

PacifiCorp filed this application on January 26, 2001, pursuant to ORS 757.495 and OAR 860-027-0040. The company seeks a Commission order finding that since 1979, its coal supply agreement with BCC, has previously been considered and approved in its prior general rate cases. Alternatively, PacifiCorp, in an effort to eliminate any questions of compliance with statutory requirements governing affiliate transactions, seeks a Commission order approving its coal supply agreement with BCC.

PacifiCorp owns a two-thirds interest in the Jim Bridger coal-fired steam electric generating plant in Wyoming. This generating plant obtains a substantial majority of its needed coal supply from BCC, a joint venture owned one-third by an Idaho Power Company subsidiary and two-thirds by Pacific Minerals, Inc.(PMI), an indirect wholly owned subsidiary of PacifiCorp. The joint venture owns significant leases covering coal deposits located near the Jim Bridger generating plant. Affiliated interest relationships exist between PacifiCorp and BCC, and between PacifiCorp and PMI.

Currently, the PacifiCorp and BCC relationship is governed by the Third Restated and Amended Coal Sales Agreement, dated January 1, 1996 (Third Restated Agreement) and the First Amendment thereto of January 1999. Together they are known as the Coal Supply Agreement. The agreement establishes annual base tonnages for coal purchases

which for 2000 and 2001 are 5,232,600 on a total system basis. Coal prices are determined through establishment of component base price, consisting of several costs related to BCC coal operations, as adjusted pursuant to the price change provision in the agreement.

The company states that BCC coal provides it with advantages such as a consistently reliable coal source and a minimization of fuel transportation and handling costs. Historically, from 1990 through 1999, the average cost of coal provided by the Coal Supply Agreement ranged from $3 to $9 per ton less than the average market price of Southern Wyoming coal delivered to the plant.

Therefore, PacifiCorp believes that the Coal Supply Agreement provides it with a reliable, long-term source of low-cost coal for the operation of the Jim Bridger generation plant. Further, the company states that since it was limited, for ratemaking purposes, to prudently incurred coal expenses plus a reasonable return on the Company's coal investment, the Commission should determine that the Coal Supply Agreement is not contrary to the public interest. Staff believes that the appropriate standard the Commission has used and continues to use for ratemaking is its affiliate interest transfer-pricing requirements, namely that the price is the lower of cost or fair market rate. See further discussion below.

Issues

I have investigated the following issues:

1. Scope and Terms of Agreement
2. Transfer Pricing and Allocation Methods
3. Public Interest Compliance
4. Records Availability, Audit Provisions, and Reporting Requirements

Scope and Terms of Agreement – Based upon my analysis of the agreement, there appear to be no unusual or restrictive terms that would harm customers. Accordingly, I am not concerned about this issue.

Transfer Pricing and Allocation Methods – The Commission's transfer policy for goods and services purchased by a regulated electric utility from an affiliate shall be priced at the lower of cost or fair market rate. This policy likely has been met because BCC is charging PacifiCorp a price for its coal supply based on BCC's fully distributed cost that is currently less than the market rate. The company's rate of return used in billing from BCC to PacifiCorp is at the same rate authorized by the Commission in PacifiCorp's most recent rate case. This is consistent with the Commission's affiliated interest (AI) transfer pricing policy. Proposed ordering condition No. 4 is included to ensure that PacifiCorp adheres to the Commission's policy.

Public Interest Compliance – PacifiCorp's customers are likely not harmed by this transaction, because the company is paying, with the provision of my proposed ordering condition No. 4, a fair and reasonable price for the coal supply. Therefore, the purchase price meets the lower of cost or fair market requirement of the Commission AI transfer pricing policy. Also, Staff noted that in 2000 and estimates for 2001, the average price savings per ton to PacifiCorp from the BCC Coal Supply Agreement are trending lower. If there should be a further lowering of the savings to PacifiCorp and its customers, it may necessitate a modification to the transfer price to meet the Commission's AI policy. This would then require PacifiCorp to comply with proposed ordering condition No. 3 to protect the public's interest.

Records Availability, Audit Provisions, and Reporting Requirements – Proposed ordering condition No. 1 provides the necessary records access to BCC's relevant books and records

CONCLUSIONS:

Based on an investigation and review of the application, I conclude the following:

1. PacifiCorp is a regulated electric company, subject to the jurisdiction of the Public Utility Commission of Oregon.

2. An affiliated interest relationship exists between PacifiCorp and Bridger Coal Company.

3. The application is fair and reasonable and not contrary to the public interest.

DETAILED RECOMMENDATION:

I recommend that the Commission approve PacifiCorp's alternative request, namely, the application of PacifiCorp for a Coal Supply Agreement with Bridger Coal Company, an affiliated interest and include the following standard Commission conditions in this matter:

1. PacifiCorp shall provide the Commission access to all books of account, as well as all documents, data, and records of PacifiCorp and BCC's affiliated interests which pertain to transactions between PacifiCorp and BCC.

2. The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any rate proceeding or alternative form of regulation.
3. PacifiCorp shall notify the Commission in advance of any substantive changes to the agreement, including any material changes in any cost. Any changes to the terms which alter the intent and extent of activities under the agreement from those approved herein shall be submitted in an application for a supplemental order (or other appropriate format) in this docket.
4. For accounting purposes, the return component used in calculating PacifiCorp's cost of service received from BCC shall be limited to the PacifiCorp's current authorized overall rate of return.

Q. **Please compare Bridger Mine costs relative to other supply options.**

A. The Company's fueling strategy was developed to insure low cost, optimum quality, and a secure long-term coal supply for the Company's plants. The Bridger Mine continues to be the optimum long-term coal supply for the Bridger Plant, in combination with the Black Butte Mine agreement. The Southwest Wyoming coal market represents a niche market, with total annual production estimated at only 15 million tons. The Bridger and Naughton Plants consume approximately 11.5 million, or 75 percent of the native production. Most of the remaining local production is consumed by nearby industrial customers. The Company has contracted for all available supplies from the Black Butte Mine. There is no additional capacity in the area to supply the Bridger Plant.

Q. **Outside of the Southwest Wyoming area, what options are available to supply the Bridger Plant?**

A. Powder River Basin ("PRB") coals are the most feasible market alternative for supplying the Bridger Plant. These supplies are located approximately 560 miles from the plant, so transportation costs are a major cost driver. The Company has periodically evaluated PRB coals relative to the Bridger Mine. Without considering the capital modifications to the unloading facility nor the retrofitting of the generating units to burn PRB coals, PRB coal is still more expensive. Based on the latest Union Pacific rail transportation proposal, the delivered cost of PRB coal is over $5/ton higher than coal from the Bridger Mine in the test period. Thus, coal from the Bridger Mine remains below the costs of any market alternative available to the Company.

that the Coal Supply Agreement is in the public interest under the provisions of ORS §§ 757.490 and 757.495.

6. Annual Bridger Coal Costs and Recording of Costs

The coal supply agreement determines the annual Bridger coal costs as described in Application Section 5 above. Expenditures and coal investments are charged to accounts in the manner directed by the Federal Energy Regulatory Commission regulations and the Commission's rules.

7. Reasons for Procuring Coal from Bridger Coal Company

In 1969, PacifiCorp's predecessor (Pacific Power & Light Company) and Idaho Power Company agreed to construct and operate the Jim Bridger generation plant. The utilities possessed joint ownership of certain leases covering coal deposits acquired from the Union Pacific Railroad, the United States Government and the State of Wyoming located near the generation plant site. The obvious advantage of construction of a generating plant near the plant's fuel source is that fuel transportation and handling costs would be minimized. In addition, Bridger Coal Company coal is of high quality, with BTU content typically ranging from 9200 to 9400 BTU per pound. This is a high BTU content for Wyoming coal. The generation plant facilities were designed to burn the type and quality of coal from these locations. Approximately 70 percent of the Jim Bridger generation plant's coal requirement is obtained from the adjacent mine owned and operated by the Bridger Coal Company.[2]

PacifiCorp's decision to execute the coal supply agreement was tied inextricably to the Company's decision to take advantage of construction of a generating plant near a source of quality fuel.

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[2] Most of the remaining generation plant coal needs are purchased from the Black Butte Coal Company. The Black Butte Mine is located approximately 17 miles from the Jim Bridger generation plant and operates in the same coal seam that is being mined by the Bridger Coal Company. Thus, the two coal supplies are of comparable quality.

b. Bridger Coal is unregulated. It is theoretically capable of earning an unlimited rate of return. This could lead to a windfall to PP&L shareholders by PP&L ratepayers.

c. The original base price of $3.75 may not have been reasonable. The actual costs of Bridger Coal may not bear a close relationship to indices used to adjust coal price.

The staff's ideal coal price would be one permitting Bridger Coal to recover expenses and earn a fair and reasonable rate of return. Staff would allow a 10.06 percent rate of return via a $7.07 per ton coal price on sales to PP&L.

Staff's repricing of PP&L coal purchases is based on the theory that a corporation should not be permitted to fragment a utility enterprise by use of affiliated corporations and thereby obtain an increased rate of return for its activity. See Pacific N. W. Bell v. Sabin, 21 Or. App. 222, 534 P.2d. 984 (1975), rev. denied.

Staff believes this is what PP&L is doing in the case of Bridger Coal. However, the effect of staff's adjustment is to hold Bridger Coal's equity return rate equal to the equity return rate staff recommends for PP&L.

3. Company's Position

The company maintains it is not bound by the terms of the Sabin decision. It argues that there are significant differences in its relationship with Bridger Coal Company and Pacific Northwest Bell's relationship with Western Electric Company because: (1) The investment in Bridger Coal was substantially more risky than a utility investment, and (2) Unlike the telephone affiliates, an alternate market exists for coal sold to PP&L at a price higher than the price charged PP&L ratepayers. The company asserts that the $7.78 price is reasonable because it is below a current fair market price for Bridger Coal -- $15.00.

4. Discussion

The company provided no figures to refute staff's calculation that Bridger Coal's return on investment at the $7.78 sales price would be 18.06 percent, or that its return on common equity would be 36.80 percent. The company acknowledges the Bridger surface mine in design and geology. The new agreement replaces an existing agreement that expires in December 2009. The 2010 price under the new contract is approximately 34 percent higher than the 2008 coal price. This 2010 pricing takes into account lower priced carryover tonnage from the prior contract. Excluding the carryover tonnage, the new contract price increase is over 50 percent.

Q. Please provide an overview of cost increases at the Bridger Mine reflected in this filing.

A. Bridger Mine costs in the 2010 TAM are projected to increase from $29.37/ton in 2008 to $33.54/ton in 2010. The Bridger Mine is located in Southwest Wyoming and operated by the Bridger Coal Company ("BCC"). It consists of two different mining operations: an underground mine and a surface mine. The Bridger Mine is subject to substantially increased taxes and royalty payments in the test period due to higher valuations driven by higher market prices. Higher production taxes and royalties, alone account for approximately $1.70/ton cost increase in 2010, more than 40 percent of the total increase.

Q. How has the Bridger surface mine changed in recent years?

A. For many years, BCC was able to extract coal at the Bridger surface mine using low-cost highwall mining. The mine has now reached the stage, however, where BCC has replaced this production method with higher-cost dragline mining to properly steward the resources of the mine. Additionally, current accounting pronouncement EITF04-6 requires that production costs be assigned only to extracted coal, not coal that is uncovered but remains in the pit. This contributes to higher costs in 2010 because more coal is scheduled to be uncovered than will actually be extracted; the opposite will be true in a year when previously uncovered coal is ultimately extracted.

Q. **Do Bridger surface mine costs in this case also reflect an increase associated with final reclamation charges?**

A. Yes. The current filing includes a new contribution charge of $0.84/ton for final reclamation. This reclamation charge reflects the most recent final reclamation study prepared by BCC as well as BCC's trust fund balance as of December 2008. The trust fund is utilized to perform final reclamation and monitoring activities required under the Surface Mine Control and Reclamation Act of 1977. Trust fund earnings in 2007 and 2008 were negatively impacted by the downturn in the economy.

Q. **What other specific drivers are causing Bridger Mine costs to increase?**

A. Other major contributing factors include:

- Increases in labor costs due to an increase in workforce size and wage and benefit increases,
- Commodity cost escalation,
- Maintenance cost increases as mining equipment is scheduled for rebuilds, component exchanges, etc., and
- Increases in depreciation, depletion and amortization expense of approximately $0.30/ton associated with additional mine infrastructure placed in service in 2010.

OPUC Data Request 51

Concerning PPL (TAM)/200, Lasich/4-5:

a. Concerning the higher costs in 2010, approximately how much of the variance from 2009 costs is attributable to dragline mining?
b. Will dragline mining be the method to surface mine in subsequent years? Please explain.
c. Approximately how much of the variance from 2009 costs is attributable to EITF 04-6?
d. Does PacifiCorp anticipate extracting more coal than uncovered in 2011? Please explain.
e. Has PacifiCorp been provided with an estimated/budgeted 2011 surface mining cost from BCC? If so, please provide and explain the estimated/budgeted cost.

Response to OPUC Data Request 51

a. Bridger Coal Company 2010 test period costs are $33.54 with EITF 04-6 and $30.63/ton without EITF 04-6. The 2009 forecast of $30.57 would increase to $30.69/ton without EITF 04-6. The impact of EITF 04-6 accounts for almost all of the variance in Bridger Coal Company mine costs between 2009 and 2010.

b. Yes, the supply of coal from Bridger Coal Company to the Jim Bridger Plant will include coal production from the underground and surface mines. The draglines will continue to be used by Bridger Coal Company to remove overburden.

c. See Response OPUC 51.a above. The impact on PacifiCorp of EITF 04-6 is to increase Bridger Coal Company costs in 2010 by $10.86 million and to decrease 2009 costs by $.48 million in 2009.

d. PacifiCorp does not have a current 2011 mine plan for Bridger Coal Company. Bridger Coal Company is in the process of developing a long-term mine plan. The 2011 mine plan, including both tonnage uncovered and extracted, will not be available until later this fall.

e. See above.

December 31, 2009

Subject: Docket No. UE 214
Idaho Power Company's Responses to Staff's Data Requests 20-21

<u>STAFF'S DATA REQUEST NO. 20</u>:

As a follow-up to IPC's response to Staff Data Request #1, please explain the third party deferred pricing.

a. Is this price added to the spot price to determine the cost for the associated delivery or is it a stand-alone price per ton?

b. For each month, please provide the total cost and average cost per ton for the third party mine based on tons delivered.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 20</u>:

a. The line item entitled "Black Butte Mine – Deferred / Force Majeure" represents the contract price of $11.07 per ton for coal to be delivered in 2010 from the Black Butte mine (stand-alone price per ton). The tonnage to be delivered in 2010 was deferred or delayed from prior years, either because of decreased coal requirements at the Jim Bridger Plant or force majeure events. This is the total cost per ton, FOB mine.

b. Please see the attached Excel spreadsheet.

Q. Please explain how EITF 04-6 impacts Bridger mine's 2010 costs.

A. Pursuant to FASB standard EITF 04-6, Bridger mine is required to include stripping costs in the cost of coal that is extracted in a given year, even if the stripping results in "uncovered" inventory available for extraction in subsequent years. The effect of this accounting requirement is that the cost of coal extracted in years when more coal has been uncovered than extracted, as a result of overburden stripping, is more expensive than coal extracted in years where more coal has been extracted than uncovered. Depending on certain variables, including mining practices, geology and production schedules, coal may or may not be extracted in the same year stripping costs have been incurred.

In 2010, the Company is expected to incur stripping costs for coal that will remain in the mine and be extracted in later years. This results in higher costs for the coal actually extracted in 2010. This will result in an increase in the cost of the surface mine operations, from approximately $39 per ton to $57 per ton, and an increase in the overall cost of Bridger coal from $30.63 per ton to $33.54 per ton. As noted in Staff's footnote 22, the 2009 weighted cost of Bridger coal was $30.57 per ton. Viewed in this manner, it is clear that the 2010 cost increase at the Bridger mine is largely related to EITF 04-6.

Q. Why is the impact of EITF 04-6 in this filing more pronounced than in previous years?

A. Bridger mine was first required to comply with EITF 04-6 in 2006. Due to our objective to focus mining operations to implement a least-cost mine plan, Bridger mine has decreased extraction of surface coal and increased underground mining as surface mine stripping ratios increase, thus increasing costs. As a result, there is a greater disparity in years where stripping costs are incurred and when coal has been extracted. In future years, the magnitude of the disparity will fluctuate depending on the amount of coal extracted.

The Company is required to comply with this accounting standard. While ICNU recommends that the Commission normalize (*i.e.* eliminate) the costs in the case resulting from this accounting change, ICNU provides no justification or basis for denying the Company recovery of these costs as unnecessary, unreasonable or imprudent.

Q. **How does the Company propose to handle the impacts of EITF 04-6?**

A. In August 2009, the Company plans to file accounting applications in all states seeking to establish a regulatory asset balancing account that would reduce the volatility of coal costs from the Bridger mine and return the Company to the accounting methods that were used prior to the adoption of EITF 04-6. Under this approach, coal costs in rates would be based on "uncovered" inventory (prior to EITF implementation) rather than the EITF "extracted" inventory method. The Company will seek to receive approval of the accounting orders in time to reflect the impact in rates by January 1, 2010. In the case of the Oregon TAM, the Company will seek an order in time to allow the final TAM update to reflect this accounting treatment and eliminate the artificial increase in coal costs caused by the accounting pronouncement and creates a timing mismatch of assigning stripping costs only to the extracted coal. Such an order would result in an effective price for 2010 Bridger coal supply that approximates 2009 levels.

PUBLIC UTILITIES COMMISSION

OF IDAHO

CASE NO. 1PC-E-10-01

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COMMENTS AND PROTEST OF

INUDSTRIAL CUSTOMERS OF IDAHO POWER

EXHIBIT 2

IDAHO POWER'S RESPONSE TO INDUSTRIAL CUSTOMER'S

PRODUCTION REQUEST 21

MARCH 11, 2010

REQUEST NO. 21: As a follow-up to Idaho Power's response to ICIP's Request for Production No. 1 in this docket (Oregon PUC Staff's Data Request No. 1 in Oregon PUC Docket No. UE 214), please explain the difference in BCC total production cost per ton and BCC sale price per ton.

RESPONSE TO REQUEST NO. 21: The BCC sales price per ton includes an operating margin, equal to the overall rate of return authorized in general rate cases where IERCO/BBC operations are treated as part of the regulated activities of the Company. The sales price is adjusted periodically as updated BCC mining expense data becomes available.

The response to this Request was prepared by Tom Harvey, Joint Projects Manager, Idaho Power Company, in consultation with Barton L. Kline, Lead Counsel, Idaho Power Company.

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CASE NO. 1PC-E-10-01

COMMENTS AND PROTEST OF

INUDSTRIAL CUSTOMERS OF IDAHO POWER

REDACTED CONFIDENTIAL EXHIBIT 3

IDAHO POWER'S RESPONSE TO INDUSTRIAL CUSTOMER'S

PRODUCTION REQUESTS 1 & 4

MARCH 11, 2010

CONFIDENTIAL – SUBJECT TO ATTORNEY'S CERTIFICATE

OF CONFIDENTIALITY

REQUEST NO. 1: For each month in 2010, please provide information in the following table format. (BCC equals Bridger Coal Company.)

	January	February	March	Etc
BCC Surface cost per ton (with EITF 04-6 effect)				
BCC Underground cost per ton				
BCC Incremental cost per ton (if applicable)				
BCC Total cost per ton				
3rd Party coal cost per ton (list separately for each supplier)				
3rd Party coal transportation cost per ton (list separately for each supplier)				
Total Bridger Costs				
BCC Surface Cost per ton (without EITF 04-6 effect)				

RESPONSE TO REQUEST NO. 1: Please see the enclosed CD.

Since this data is confidential, Idaho Power is providing this information only to parties that have executed the Protective Agreement.

The response to this Request was prepared by Kent Christensen, Joint Venture Analyst, Idaho Power Company, in consultation with Barton L. Kline, Lead Counsel, Idaho Power Company.

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CONFIDENTIAL

THIS EXHIBIT ALLEGEDLY CONTAINS TRADE SECRETS OR CONFIDENTIAL MATERIAL AND IS SEPARATELY FILED.

REQUEST NO. 4: Concerning the Direct Testimony of Scott Wright at pages 8-9, please provide the 2007, 2008, 2009, and 2010 cost per ton for each (affiliate and third party) coal supplier for Bridger in the following table format. Please list each supplier separately. Please provide applicable pages, of contract that lists pricing.

	2007	2008	2009	2010
BCC				
Bridger 3rd party				

RESPONSE TO REQUEST NO. 4: Please see the enclosed CD which contains a spreadsheet and applicable pages of amendments and contracts that list pricing.

Since this data is confidential, Idaho Power is providing this information only to parties that have executed the Protective Agreement.

The response to this Request was prepared by Kent Christensen, Joint Venture Analyst, Idaho Power Company, in consultation with Barton L. Kline, Lead Counsel, Idaho Power Company.

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OF IDAHO

CASE NO. 1PC-E-10-01

COMMENTS AND PROTEST OF

INUDSTRIAL CUSTOMERS OF IDAHO POWER

REDACTED CONFIDENTIAL EXHIBIT 4

IDAHO POWER'S RESPONSE TO COMMISSION STAFF'S

PRODUCTION REQUEST 3

MARCH 11, 2010

CONFIDENTIAL – SUBJECT TO ATTORNEY'S CERTIFICATE

OF CONFIDENTIALITY

REQUEST NO. 3: Please provide an analysis showing the current all-in cost of coal for Bridger by coal source (i.e. Bridger coal, Black Butte coal, market, etc.)

RESPONSE TO REQUEST NO. 3: Please see the attached spreadsheet showing the current all-in cost of coal for Bridger by coal source. The Bridger Plant does not rely on any market purchases of coal. The actual sales price per ton for January Black Butte deliveries reflects amounts of coal deferred from prior periods of time at prior contract prices into the January 2010 time period. Since this data is confidential, Idaho Power is providing this information only to parties that have executed the Protective Agreement.

The response to this Request was prepared by Kent Christensen, Joint Venture Analyst, Idaho Power Company, in consultation with Barton L. Kline, Lead Counsel, Idaho Power Company.

CONFIDENTIAL

THIS EXHIBIT ALLEGEDLY CONTAINS TRADE SECRETS OR CONFIDENTIAL MATERIAL AND IS SEPARATELY FILED.

CERTIFICATE OF SERVICE

RECEIVED
2010 MAR 11 PM 3: 08
IDAHO PUBLIC UTILITIES COMMISSION

I HEREBY CERTIFY that on the 11th day of MARCH 2010, a true and correct copies of the within and foregoing redacted and confidential versions of the COMMENTS AND PROTEST OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER were served in the manner shown to:

Ms. Jean Jewell Commission Secretary Idaho Public Utilities Commission P O Box 83720 Boise, ID 83720-0074	X Hand Delivery __ U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
Scott Woodbury Commission Secretary Idaho Public Utilities Commission PO Box 83720 Boise, ID 83720-0074	X Hand Delivery __ U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
Lisa Nordstrom Barton L. Kline Idaho Power Company PO Box 70 Boise, Idaho 83707-0070	__ Hand Delivery X U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
Gregory W. Said Idaho Power Company PO Box 70 Boise, Idaho 83707-0070	__ Hand Delivery X U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
Eric L. Olsen Racine, Olson, Nye, Budge & Bailey, Chartered P.O. Box 1391; 201 E. Center Pocatello, Idaho 83204-1391	__ Hand Delivery X U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
Anthony Yankel 29814 Lake Road Bay Village, Ohio 44140	__ Hand Delivery X U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail

Nina M Curtis

Nina Curtis
Administrative Assistant