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BARTON L. KLINE
Lead Counsel
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March 23, 2010

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-10-01
IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY TO ESTABLISH ITS BASE LEVEL FOR NET POWER SUPPLY EXPENSES FOR 2010

Dear Ms. Jewell:

Enclosed please find for filing an original and seven (7) copies of Idaho Power Company's Reply Comments in the above matter.

Very truly yours,

Barton L. Kline

BLK:csb
Enclosures

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

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IDAHO PUBLIC UTILITIES COMMISSION

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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 REPLY COMMENTS OF IDAHO POWER COMPANY

COMES NOW Idaho Power Company ("Idaho Power" or the "Company") and hereby responds to the Comments filed in this case by the Commission Staff ("Staff") the Industrial Customers of Idaho Power ("ICIP") and the Idaho Irrigation Pumpers Association, Inc. ("Irrigators"). ICIP and Irrigators are sometimes collectively referred to as "Intervenors."

I.

BACKGROUND

The Comments of the Staff and ICIP have provided a detailed description of the procedural background that led to the filing of this case. There is no need to repeat all of that history in these Comments. Idaho Power's intention to file this case was expressed in the Settlement Stipulation the Commission approved in Case No. IPC-E-09-30. All of the Parties in this case signed that Stipulation and agreed that the rate case moratorium approved in Order No. 30978 would not apply to a case such as this one where the Company is asking to update its Net Power Supply Expenses ("NPSE") from the currently approved 2008 levels to 2010 levels.

II.

ISSUES TO BE ADDRESSED

For the most part, Staff, Irrigators and ICIP identify the same items as potential adjustments to the NPSE filed by the Company. Attachment A to Staff's Comments assigns a value to each of these items based on the differences between the Company's cost for an item in its 2008 NPSE and the cost of the item in the 2010 NPSE filed in this case. These Comments will address the items at issue in the order of the magnitude of their impact on the Company's request in this case.

A. Increased Bridger Coal Costs.

Undoubtedly, the single biggest cause of the increase in NPSE for 2010 is the fact that the Company is going to have to pay more for the coal it burns to fuel its Jim Bridger Power Plant ("the Bridger Plant" or "Plant") than it did in 2008.

Idaho Power and PacifiCorp co-own the Bridger Plant, and its associated mining operation, the Bridger Coal Company ("BCC"). The Plant is run primarily on coal from the BCC's surface and underground mining operations. Supplemental coal is purchased from the nearby Black Butte mine ("Black Butte"), which is operated by Kiewit Mining. The Bridger Plant was designed and constructed as a "mine-mouth" plant, which means it is physically located next to the coal mine that supplies the majority of its coal. This arrangement ensures that the Plant has access to a continuous and reliable supply of coal. Coal is delivered to the Plant from the BCC mine by use of a large conveyor belt system that transports and delivers coal directly from the mining operation into the Plant. This type of mine-mouth plant operation has several advantages over an operation where the coal is delivered from another location. First, the mine-mouth operation has the obvious advantage of eliminating the need to ship coal over long distances in order to supply the generating plant – usually at great expense and subject to transportation interruptions. In addition, the mine-mouth operation avoids the undesirable result of locating the coal-fired generation plant in close proximity to large population centers, which typically correspond to the large load centers.

The BCC surface mine commenced commercial operation in August 1974 and has been producing coal for the Bridger Plant since that time. BCC started producing coal from its underground mining operations in March 2007. The surface and underground mines are run as an integrated operation. While the underground mine provides the majority of the coal to the Bridger Plant, the surface operation provides: (1) coal critical to the blending process, (2) additional overall mine capacity, (3) flexibility in running the underground operations, (4) a hedge against increased prices of non-owned coal, and (5) support for the costs common to both the surface and underground operations of BCC.

In their Comments on the Bridger Plant coal cost issue, Idaho Staff and Intervenors all note that the Staff of the Public Utility Commission of Oregon ("OPUC") has filed testimony in a current Company proceeding in Oregon in which the Oregon Staff recommends a downward adjustment to Bridger Plant coal costs. OPUC Staff asserts that the costs of the surfaced-mined coal purchased by the Company from BCC for the Bridger Plant exceeds the cost of coal from the Black Butte mine and therefore purchases of BCC surface coal violates the OPUC's "lower of cost or market" rule. OPUC Staff argues that the two companies should have reduced their purchases of BCC's surface coal – which is more expensive to produce than BCC's underground coal – and made additional purchases from the Black Butte mine.

In this Idaho case, the Comments of the ICIP make a similar recommendation for a downward adjustment to the Company's filed Bridger coal expense. The ICIP adopts the same arguments and cost calculations advanced by the OPUC Staff in the Oregon case to support its recommendation in this case. Idaho Power has carefully reviewed the analyses and arguments presented by the OPUC Staff in support of its recommendation in Oregon. Based on that review, the Company has concluded that OPUC Staff's recommendation is fundamentally flawed. First, Black Butte does not have sufficient production capacity to mine enough coal to replace the BCC surface coal volumes the Plant needs. While Black Butte *may* have a small amount of additional capacity to produce coal, that additional coal will cost more than the savings attributable to the BCC coal it would replace. Second, OPUC Staff improperly calculated the cost of BCC's surface coal when it compared the cost of BCC coal to the cost of Black Butte coal. The Company's analysis shows that following the OPUC Staff's recommendation and eliminating purchases of BCC surface coal and replacing that coal with Black Butte coal would increase the annual cost of coal for the Bridger Plant by approximately $6 million per year. Third, the non-price benefits of the BCC contract to Idaho Power's customers are substantial. These benefits include the use of BCC coal in the blending process to produce a mixture that allows the most efficient operation of the Bridger Plant. Availability of BCC surface coal adds valuable flexibility for the Plant to use BCC operations as a hedge against unexpected production decreases at Black Butte and to provide protection against possible future price increases for non-owned coal.

These Comments provide support for the Company's conclusion that the OPUC Staff, and therefore the ICIP, are basing their recommendations for a downward adjustment to Bridger Coal costs on erroneous analyses. However, the task of developing and implementing a prudent long-term strategy for providing fuel for a large coal-fired power plant like the Jim Bridger plant, is complex. To help the Commission gain a better understanding of the Company's Bridger fuel strategy, Idaho Power has enclosed with these Comments three attachments. The first attachment is a "white paper" which has previously been provided to the parties to this case in discovery. Attachments Nos. 2 and 3 are the reply testimony and exhibits of Greg Said and Tom Harvey which were filed with the Oregon Public Utility Commission on Wednesday, March 17, 2010. These three documents provide an in-depth analysis of the reasons why the OPUC Staff's recommendation (and therefore ICIP's recommendation) for a downward adjustment in Bridger fuel costs is neith er logical no r in Idaho Power's customers' best interest fair. These Comments will make periodic references to specific portions of those three Attachments. Attachments Nos. 1, 2, and 3 provide detailed, verifiable evidence exposing the flaws in the OPUC Staffs' position on Bridger coal costs in the Oregon case and ICIP's similar positions in this case.

1. ICIP Erroneously Concludes That Additional, Lower Cost, Black Butte Coal Is Available.

On page 7 of its Comments, ICIP acknowledges that it has been advised 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." (ICIP Comments, p. 7.) However, ICIP then states that in the Company white paper (Attachment No. 1) Idaho Power has admitted that [redacted] of lower cost Black Butte coal is available. Idaho Power has made no such admission.

In its white paper and as Mr. Harvey notes on lines 13 through 17 on page 11 of his reply testimony (Attachment No. 3), even if Kiewit Mining has the capacity to produce [redacted] of additional Black Butte coal, there is *no* evidence that the additional coal could be obtained at the same price under the existing contract. On the contrary, the price quoted by Kiewit Mining for that uncommitted production was substantially higher than the price paid to Kiewit under the existing Black Butte contract. Kiewit Mining quoted an F.O.B. mine price of [redacted] per ton with an adjuster for changes in diesel fuel costs, and for volumes, such as the above-referenced [redacted] annual tons, in excess of the new contract price. This price significantly exceeds the cost of BCC coal. As noted on pages 8-9 of Mr. Harvey's testimony (Attachment No. 3), the decremental cost of BCC surface coal is approximately [redacted] per ton. Replacing the BCC coal as recommended by ICIP would save the Company approximately [redacted] per ton and replacing it would cost at least [redacted] per ton. As a result, reducing purchases from BCC and buying more coal from Black Butte would result in an increase in overall coal costs. Additional purchases of Black Butte coal are not a viable alternative to purchases from BCC.

2. ICIP Incorrectly Concludes That Less Expensive Coal Is Available To The Bridger Plant.

OPUC Staff asserts that the "market price" for coal should be equal to the Black Butte price and that it would be less expensive if the Company were to purchase "market priced coal" than to continue to purchase from both Bridger Coal Company and Black Butte. ICIP adopts that same argument that there must be a cheaper alternative. "Nevertheless it is likely there is a cheaper alternative to continuing to use the now – very – costly surface-mine from BCC." (ICIP Comments, p. 8.) ICIP's speculation that there is less expensive coal available is unfounded. In fact, there is no less expensive market alternative and, overall, BCC coal is the lowest cost resource. In the enclosed reply testimony of Tom Harvey (Attachment No. 3) beginning on line 24 of page 7 and continuing to line 11 on page 10, Mr. Harvey explains that while BCC's surface coal is more expensive than its underground coal, the costs associated with any available replacement coal are higher than the costs that Idaho Power could avoid if the surface operation ended. As previously noted, BCC's underground and surface mines constitute one integrated operation. As a result, many of the costs to run the BCC mine are allocated to the coal produced by both the surface and underground mines. If the surface mine were shut down, which is the logical implication of ICIP's adjustment, many of the shared costs would not be avoided but would need to be reallocated to the cost of the underground coal. In other words, BCC cannot avoid all of the costs allocated to the surface coal by shutting down the surface mine. So, for the purposes of assessing whether there is a lower cost market alternative, the cost of the surface coal should be considered at the cost BCC could avoid by shutting down the surface mine – or the decremental cost of the BCC surface coal. BCC calculated the decremental cost of surface coal based upon its most currently available mine plan. Based on that analysis, the decremental cost of the surface coal at BCC is [redacted] per ton. In order to ensure a conservative estimate, the Company rounded this cost up to [redacted] per ton. The decremental cost analysis estimates that BCC would save approximately [redacted] for every ton of surface coal not mined. That sum would therefore be available to purchase replacement coal. The only mine in the relevant market, the Green River Basin, is Black Butte. Since Black Butte coal will cost at least [redacted] per ton at the Plant, it is readily apparent that OPUC Staff's and ICIP's proposal to substitute more Black Butte coal (if it were available) would be very expensive for customers.

The Company also investigated the possibility of buying coal from the Power River Basin ("PRB") in eastern Wyoming, approximately 566 miles from the Plant. Idaho Power confirmed that the estimated cost to ship coal from the PRB to the Bridger Plant is around [redacted] per ton, which is double the estimated [redacted] per ton cost of the coal itself. In total, the per ton cost of PRB coal, including transportation is likely to be at least [redacted] per ton F.O.B. plant *without* adding in the additional costs that would be incurred for freeze protection and dust suppression. Assuming that significant volumes of PRB coal could be obtained and shipped to the Plant, use of coal from the mines in the PRB would require significant capital investment in the Plant because of the different quality and make-up of the coal compared to the blend of BCC and Black Butte coal the Plant currently burns. These issues with the Powder River Basin coal make it uneconomical to consider coal from that region as a possible fuel source for the Plant.

Mr. Harvey's testimony in Attachment No. 3 demonstrates that Idaho Power has carefully considered all of the alternatives for providing fuel to Jim Bridger and has arrived at and implemented an overall fuel acquisition strategy that provides the lowest cost for customers.

3. <u>The Commission Should Allow Some Additional Time For Review of the Company's Coal Acquisition Strategy for the Bridger Plant</u>.

The Comments of the Staff and the Intervenors all suggest that the issues relating to Jim Bridger coal costs cannot be finally resolved prior to the Company's April 15, 2010, PCA filing. All three commentors indicate that because of the compressed schedule for this case, they have been unable to complete their review of this issue. Staff and the Intervenors suggest that the Commission undertake further review of the coal cost issue in a subsequent proceeding. (See Staff Comments, p. 4; ICIP Comments, p. 9; and Irrigators Comments, p. 9.) Idaho Power is confident that further review of this issue by the Commission will result in a Commission determination that Idaho Power has acted prudently in managing its fuel costs for the Jim Bridger plant. For that reason, the Company would not object to the Commission setting a reasonable schedule for further proceedings to allow Staff and the Intervenors more time to review Idaho Power's long-term strategy for acquiring coal for the Jim Bridger Plant.

The question then posed is what is the most appropriate ratemaking treatment for Bridger coal costs during this additional review period? Idaho Power disagrees with the position of the ICIP and the Irrigators that until such time as the Commission completes its review of the Bridger coal cost issues, the Company's coal acquisition strategy for the Bridger Plant should be treated as imprudent and the Company should be denied recovery of its increased coal costs in its NPSE. This approach punishes the

Company without providing any additional protection to customers. The Commission Staff proposes a different approach. In its Comments, Staff stated:

> Based on the information received to date, Staff has not identified any justification for adjusting 2010 Bridger coal costs. Consequently, Staff recommends that for now, Bridger coal costs be allowed at the level proposed by Idaho Power in its Application, but that the Commission reserve the right to make adjustments to Bridger coal costs allowed in base rates in the context of Idaho Power's 2010 PCA filing. The Company's annual PCA filing is expected to be submitted on April 15, 2010, with a final order due on May 15 in order to accommodate rate changes that would be effective on June 1. (Staff Comments, p. 4.)

Idaho Power supports Staff's proposed ratemaking treatment because it is the fair to both the Company and its customers.

ICIP's disagreement with Staff's proposal is based on misunderstanding of how costs would be allocated between the Company and customers in the PCA if the Commission were to ultimately conclude that the Company had acted imprudently in its coal sourcing strategy. On page 11 of its Comments, ICIP argues that:

> If the Commission allows these costs (2010 Bridger Coal surface mining costs) into the base level NPSE for 2010 and then determines after June 1, 2010, that they are not prudent expenses, rate payers would lose the ability to ever recover a refund of 5 percent of the imprudent costs incurred after June 1 through a future PCA. (ICIP Comments, p. 11.)

ICIP misunderstands the PCA process. Imprudent costs are not subject to the 95 percent/5 percent sharing. If the Commission were to find that the Company's acquisition of Bridger Coal Company coal is imprudent, *100 percent* of the imprudent costs would be returned to customers. There is a zero chance that customers will be disadvantaged if Idaho Power is permitted to include its proposed 2010 Bridger coal costs in its base level NPSE during the pendency of the review period. On the other hand, if the Commission were to adopt ICIP's recommendation and assume today that the Company's decision to buy BCC surface coal was imprudent and exclude the increased costs of BCC coal from base rates, and then, after all the facts were presented, determine that the Company *had* acted prudently, the Company would only recover 95 percent of its prudent expenses in a future PCA proceeding. This would be a manifestly unfair and unnecessary result.

In summary, the enclosed Attachments Nos. 1-3 demonstrate that OPUC Staff (and therefore ICIP) improperly calculated the cost of Bridger Coal Company surface coal for comparison to alleged market alternatives. When the prices are properly calculated, the cost the Company will avoid if it replaces the BCC surface coal with coal with Black Butte is actually less than it would pay for the replacement coal – assuming sufficient Black Butte replacement coal could be obtained, which it cannot. Second, using Black Butte coal as a proxy for the market is not valid because there is not sufficient Black Butte coal to replace Bridger Coal Company surface coal. Third, under any reasonable scenario, it is clear that overall, BCC coal is the lowest cost resource. Fourth, the non-price benefits of the Bridger Coal Company Contract to Idaho Power's customers are substantial. These non-price benefits include the use of BCC coal in the blending process to produce a blend of coal that optimizes generation at the Bridger Plant and the flexibility to use BCC operations as a hedge against production shortfalls at Black Butte and price increases for non-owned coal. The evidence presented in these Comments demonstrates that the substitution of more Black Butte coal for Bridger Coal Company coal is impractical and will increase Idaho Power Company's customers' risks and costs of power over both the short and long terms.

4. Idaho Power Purchases from BCC Do Not Raise Any Issue of Cross-Subsidization.

Idaho Power has an affiliate relationship with a company called Idaho Energy Resources Company ("IERCO"). IERCO owns a one-third interest in BCC. In 1974, PacifiCorp and Idaho Power entered into a long-term coal sales agreement with BCC. Throughout its Comments, ICIP warns that because BCC is affiliated with Idaho Power, the Commission should be particularly vigilant in reviewing Idaho Power's Bridger Plant coal acquisition strategy. ICIP's concern is not well founded. Since the mid-1970s, the Commission has been aware of and acknowledged that the transactions between Idaho Power and BCC pose no risk of cross-subsidization because of the unique manner by which the Commission addresses IERCO's (the affiliate that owns BCC) operations for ratemaking purposes. Unlike other utility affiliates, for ratemaking purposes, IERCO's operations are merged with those of Idaho Power. The Oregon PUC summed up the situation in Order No. 91-566 when it approved the contract between Idaho Power and BCC as follows:

> . . . IERCO's results of operations have been merged, consolidated, and included with Idaho's for purposes of filing of income tax returns and for ratemaking purposes, 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 hire 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. (OPUC Order No. 91-567 at p. 2.) (Emphasis added)

While ICIP admits on page 5 of its Comments that there is "little risk" of cross-subsidization of BCC by Idaho Power and its customers, ICIP argues that this affiliate relationship should still make the Commission nervous. In fact, on page 12 of its Comments, ICIP urges the Commission to issue a new order requiring that when Idaho

Power's affiliate sells serves or supplies to Idaho Power, the sales be recorded in the utility's accounts at the affiliates cost or the market rate, whichever is lower. ICIP asserts that Idaho has no official policy on how to charge rate payers for a utility's affiliate provided expenses. (ICIP Comments p. 12.) At least with respect to Idaho Power, ICIP's understanding of Commission policy is in error. In Order No. 30530 issued in Case No. IPC-E-01-08, the Commission approved a Revised Code of Conduct for Idaho Power, IDACORP, and the Commission Staff that does precisely what ICIP now requests the Commission to do. Specifically paragraph 8(g) of the Revised Code of Conduct attachmed to Order No. 30530 provides as follows:

> IDACORP and Idaho Power Company commit to use asymmetrical pricing (i.e., lower of cost or market for transactions to Idaho Power Company and higher of cost or market for transactions from Idaho Power Company) for affiliate charges or costs not covered by provisions of any cost sharing agreement or Service Level Agreements (SLA), if a readily identifiable market for the goods, services or assets exists, and if the transaction involves a cost of more than $100,000. (Revised Code of Conduct P. 2).

The Company is, and always has, purchased coal for the Bridger Plant at the lower of cost or market. No new orders or filing requirements are necessary.

VII.

ADJUSTMENT TO PURPA COSTS AND ADJUSTMENTS TO HOKU LOADS AND REVENUES

In its Comments, Staff identifies two areas where it recommends downward adjustments to the Company's proposed NPSE. The first is an adjustment to the Company's assumption of the level of expense the Company will incur to purchase energy from PURPA developers in the future. Idaho Power has signed fourteen new PURPA contracts, all of which have scheduled operation dates in 2010. Staff argues that prior history indicates that even through PURPA developers agree in their signed contracts that they will come on-line at a particular time, they often do not. In its Comments, Staff recites the history of a large group of PURPA projects that were originally scheduled to come on-line in 2007. The PURPA developer now indicates these projects will come on-line by year-end 2010. While Idaho Power has no independent knowledge that the PURPA projects it has identified for inclusion in 2010 will not be on-line in 2010, Idaho Power acknowledges that prior history adds weight to Staff's recommendation to remove the expected costs of these projects. Because the Company is allowed to recover 100 percent of costs of PURPA contracts in its annual PCA filings, the Company does not object to the adjustment recommended by Staff.

The other adjustment Staff proposes is to the Hoku loads and revenues. Staff proposes downward adjustments to the Company's net power supply expense based on the uncertainty associated with the amount of Hoku load and revenue in 2010. As it did with the PURPA contracts, Staff recites the history of the Hoku Energy Sales Agreement ("ESA") and correctly notes the delays that have been associated with that ESA. Idaho Power included the Hoku expenses and revenues based on its contract with Hoku. Idaho Power has no independent knowledge that Hoku will not perform in accordance with its contract. That being said, Idaho Power does not disagree with the Staff that there is uncertainty associated with the Hoku loads and revenues and the Company is willing to accept Staff's recommended adjustment in NPSE attributable to the Hoku ESA.

VIII.

IRRIGATORS' CRITICISMS OF THE AURORA MODEL ARE NOT WELL FOUNDED

The Irrigators' Comments spent relatively little time addressing the issues that were the focal point of Staff's and ICIP's comments, i.e., Bridger coal costs, Hoku, PURPA, etc. Instead the Irrigators focused the majority of their Comments on what they believe to be errors in the Company's computations of net power supply expenses attributable to the AURORA power supply economic dispatch model. Predictably, Irrigators characterize the AURORA model as a "black box" and argue that its results cannot be trusted.[1] Staff also reviewed Idaho Power's NPSE analysis in detail, including its AURORA results. In general, Staff concluded that the results that Idaho Power presented from its AURORA analysis were reasonable. On page 7 of its Comments, Staff stated:

> Each change in AURORA input data made by Idaho Power since its 2008 rate case was identified by Staff, its effect on NPSE was estimated, and its reasonableness considered. Staff performed multiple AURORA simulations using its own assumptions. Although Staff's results differ from the Company's due to some of the issues discussed previously, Staff's results with regard to surplus sales revenue and non-PURPA purchases are very similar to Idaho Power's results. Staff believes that the gas prices used by Idaho Power in its AURORA analysis are reasonable, and agrees that surplus sales revenue is likely to decline significantly in 2010 and the costs for non-PURPA purchases will increase due to more market purchases.

Perhaps one of the reasons the Irrigators' conclusions regarding the reasonableness of the Company's results differ so dramatically from the Staff's is that the Irrigators were not permitted to participate in the workshop held on March 2, 2010,

[1] Idaho Power has been using the AURORA model for more than 10 years. The Commission Staff has used the AURORA model for almost as long. The model's results have been reviewed and scrutinized in numerous proceedings. Hopefully, at some point AURORA will lose its "black box" status.

in which the Company, the Staff, and the other intervenors discussed some of the issues the Irrigators' raise in their Comments. Had the Irrigators participated in those discussions, perhaps their concerns could have been allayed. For example, in their Comments on pages 4 through 6, the Irrigators compare actual operations of the Company's gas peaker plants to the operations AURORA modeled results for those same units. The intent of the comparison is to show that actual generation differs from the results shown in the Company's AURORA modeling and from that the Irrigators conclude that the AURORA model must be doing something wrong. However, Irrigators' Comments fail to recognize that the modeling undertaken in this case is based on a normalized test period. In their Comments, the Irrigators are comparing *actual* monthly generation to a *normalized* annual test period. This is a classic apples to oranges comparison. This specific issue was addressed in the March 2, 2010, workshop and it was pointed out by Staff and the Company that such a comparison would be flawed and would not provide any valid insight into the reasonableness of the AURORA results used in computing NPSE.

On page 6 of their Comments, the Irrigators also asserted that there are logic problems with AURORA. In support of that assertion, they focused on modeled generation of the Valmy plant under 1982 hydro conditions and concluded that Valmy was not economic to operate under those conditions. The Irrigators' erroneous conclusion comes from a fundamental misunderstanding of the AURORA model. The AURORA model is an economic dispatch model. The Valmy plant is a baseload resource that actually operates close to or near maximum capacity whenever it can. A coal plant like Valmy is not operated to ramp up and down to meet hourly changes;

therefore, changes in loads are followed by other resources that are designed to ramp up and down, such as hydro and/or gas-fired peaking resources. Contrary to the Irrigators' assertion, during the 1982 hydro condition, Valmy is an economic resource almost all of the time. Enclosed as Attachment No. 4 is a chart comparing the Valmy operation and costs against surplus sales' prices during the similar 1982 hydro condition. As Attachment No. 4 shows, Valmy was an economic resource throughout the entire period.

In summary, none of the Irrigators' criticisms of the AURORA model are well founded and certainly do not supply adequate support for the Commission to conclude that the Company's filed NPSE for 2010 have been over stated.

IX.

CONCLUSION

In this case, Idaho Power is requesting authority to update its NPSE expenses to 2010 levels. There is general agreement among the Parties that Idaho Power should be allowed to update its NPSE, but the amount of the update is where the Parties' respective positions diverge.

Idaho Power is willing to accept a reduced 2010 NPSE increase of $63,701,694 million as proposed by Commission Staff. (Staff Comments p. 8.) Idaho Power would not object to the Commission's adoption of Staff's recommendation that Staff and Intervenors be allowed time to review Idaho Power's Jim Bridger coal costs. Based on the Company's testimony and exhibits presented in this case, including Attachments Nos. 1-3 enclosed with these Comments, Idaho Power believes it has made a *prima facie* case that it has acted prudently in planning and implementing its fuel procurement strategy for the Jim Bridger Power Plant. As such, the Commission should adopt the Staff's recommendation to allow the Company's 2010 Bridger coal costs to be included in base and PCA rates, subject to review and potential refund in the 2011 PC A. Because the Company has made a *prima facie* case, Idaho Power submits that Staff, ICIP and the Irrigators carry the burden going forward with the evidence on Bridger Coal costs. Finally, Idaho Power requests that the Commission reject the other adjustments to the 2010 NPSE as proposed by ICIP and Irrigators.

Respectfully submitted this 23rd day of March 2010.

BARTON L. KLINE
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 23rd day of March 2010 I served a true and correct copy of the foregoing REPLY COMMENTS OF IDAHO POWER COMPANY upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Weldon B. Stutzman Deputy Attorney General Idaho Public Utilities Commission 472 West Washington P.O. Box 83720 Boise, Idaho 83720-0074	_X_ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email Weldon.stutzman@puc.idaho.gov
Industrial Customers of Idaho Power Peter J. Richardson Gregory M. Adams RICHARDSON & O'LEARY 515 North 27th Street P.O. Box 7218 Boise, Idaho 83702	____ Hand Delivered _X_ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email peter@richardsonandoleary.com greg@richardsonandoleary.com
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Idaho Irrigation Pumpers Association, Inc. Eric L. Olsen RACINE, OLSON, NYE, BUDGE & BAILEY, CHARTERED P.O. Box 1391 201 East Center Pocatello, Idaho 83204-1391	____ Hand Delivered _X_ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email elo@racinelaw.net
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Barton L. Kline

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-01

IDAHO POWER COMPANY

ATTACHMENT NO. 1
IS CONFIDENTIAL AND WILL BE PROVIDED TO THOSE WHO HAVE SIGNED THE PROTECTIVE AGREEMENT

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-01

IDAHO POWER COMPANY

ATTACHMENT NO. 2

Idaho Power/200
Witness: Gregory W. Said

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 214

IN THE MATTER OF	)
IDAHO POWER COMPANY'S	)
2010 ANNUAL POWER COST UPDATE	)
	)
	)
	)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

GREGORY W. SAID

March 17, 2010

REDACTED

Q. Please state your name and business address.

A. My name is Gregory W. Said and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company as the Director of State Regulation.

Q. Please describe your educational background.

A. In May of 1975, I received a Bachelor of Science Degree in Mathematics with honors from Boise State University. In 1999, I attended the Public Utility Executive Course at the University of Idaho. Over the years I have attended numerous industry conferences and training sessions.

Q. Please describe your work experience with Idaho Power Company.

A. I became employed by Idaho Power Company ("Idaho Power" or "Company") in 1980 as an analyst in the Resource Planning Department. In 1985, the Company applied for a general revenue requirement increase. I was the Company witness addressing power supply expenses.

In August of 1989, after nine years in the Resource Planning Department, I was offered and I accepted a position in the Company's Rate Department. With the Company's application for a temporary rate increase in 1992, my responsibilities as a witness were expanded. While I continued to be the Company witness concerning power supply expenses, I also sponsored the Company's rate computations and proposed tariff schedules in that case.

Because of my combined Resource Planning and Rate Department experience, I was asked to design a Power Cost Adjustment ("PCA") which would impact customers' rates based upon changes in the Company's net power supply expenses. I presented my recommendations to the Idaho Public Utilities Commission in 1992, at which time the Commission established the PCA as an annual adjustment to the Company's rates. I sponsored the Company's annual PCA adjustment in each of the years 1996 through 2003. I continue to supervise PCA-related regulatory filings.

After the conclusion of the Company's 2004 general rate case in Oregon, which was based upon a 2003 test year, I worked with the Staff of the Public Utility Commission of Oregon ("OPUC" or "Commission"), the Citizens' Utility Board ("CUB") of Oregon, and the Industrial Customers of Oregon to develop methods to annually adjust the power supply expense related portion of Oregon rates. These methods include the October update filing of normalized power supply expenses and the March filing of forecasted power supply expenses, which are used in combination to determine the Annual Power Cost Update ("APCU") rate that will go into effect the following June, and also include the February true-up or power cost adjustment mechanism ("PCAM"), which determines an amount to be added or subtracted from the queue of power supply deferrals.

In 1996, I was promoted to Director of Revenue Requirement and in 2002 I was promoted to Manager of Revenue Requirement. I have managed the preparation of revenue requirement information for regulatory proceedings in both Idaho and Oregon since 1996.

In 2008, I was promoted to Director of State Regulation. In that capacity, I was asked by Mr. Ric Gale, Vice President of Regulatory Affairs, to lead, manage, and coordinate the preparation and development of regulatory filings in Oregon and Idaho. I supervised and coordinated the preparation of testimony in this case and I am the Company witness regarding regulatory policy.

INTRODUCTION

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

A. My testimony addresses policy issues raised by Staff witness Michael Dougherty with respect to his coal cost adjustment.[1] Mr. Dougherty proposes a significant

[1] *See* Staff/200.

adjustment of over $15 million system-wide related to the reasonable and prudently incurred coal costs for the Company's Jim Bridger Plant (the "Bridger Plant" or "Plant"). Mr. Dougherty bases his adjustment on his understanding of the Commission's lower of cost or market ("LCM") rule set forth in OAR 860-027-0048. This rule applies to transactions between a regulated utility and its affiliate. Specifically, Mr. Dougherty takes the position that the surface-mined coal purchased by the Plant from its affiliated mine—the Bridger Coal Company ("BCC")—is more expensive than market. Therefore Mr. Dougherty recommends that the cost of the surface coal from BCC be replaced for ratemaking purposes with the cost of coal purchased by the Plant from the non-affiliated Black Butte Mine ("Black Butte"). After a thorough analysis of Mr. Dougherty's reasoning I conclude that the Commission should reject Mr. Dougherty's proposal for the following reasons:

(1) Replacement coal for the Bridger Plant is not available and thus there is not a viable market as defined in the LCM rule;

(2) Staff misapplied the Commission's LCM rule, and a proper application will demonstrate that the use of BCC coal results in lower costs for the Company's customers than "market" alternatives;

(3) Staff failed to identify any unreasonable or imprudent costs incurred by Idaho Power or its affiliate;

(4) Adoption of Mr. Dougherty's adjustment will create serious policy concerns with respect to the Company's use of captive mines and long-term coal contracts that will ultimately hurt customers; and

(5) Because of the relationship between the Bridger Plant and BCC, Mr. Dougherty's interpretation of the Commission's LCM rule should not apply to this case.

SUMMARY OF STAFF RECOMMENDATION

Q. Please provide a detailed explanation of Mr. Dougherty's adjustment.

A. Mr. Dougherty's testimony includes four different analyses. He recommends the Commission adopt either his Primary or First Alternative Analysis. He also provides two additional analyses that he rejects. In his Primary, First Alternative, and Second Alternative Analyses Mr. Dougherty replaces the costs of surface-mined coal[2] from BCC because he claims the cost of the surface-mined coal exceeds the "market rate." In his Primary and First Alternative Analyses, Mr. Dougherty identifies the market rate as the cost the Bridger Plant pays for coal from the Black Butte Mine. The only difference between these two analyses is that in his Primary Analysis, Mr. Dougherty calculates the market rate by including the deferred costs paid to Black Butte under now expired contracts while in his First Alternative Analysis he uses only Black Butte's contract and transportation costs and not deferred costs. In his Second Alternative Analysis, Mr. Dougherty calculates the market rate as the cost of coal from BCC's underground operations only. And finally, Mr. Dougherty's Third Alternative Analysis replaces both the surface and underground BCC coal costs with the cost of Black Butte coal. In each instance the basis for the adjustment is Mr. Dougherty's conclusion that the costs of coal from the Company's affiliated mine exceeds the market rate for coal the Company could otherwise purchase.

Q. What is the affiliate transaction at issue here?

A. Idaho Power has a wholly-owned subsidiary called Idaho Energy Resources Company ("IERCO"). IERCO owns a one-third interest in BCC; the other two-thirds are owned by a PacifiCorp subsidiary. BCC operates a coal mine in the Green River Basin ("GRB") in southern Wyoming. BCC's mine supplies its entire output to the Bridger Plant, which is owned jointly by Idaho Power and PacifiCorp and is located adjacent to the mine. Here, the transaction at issue is the sale of coal from BCC (a subsidiary through IERCO) to Idaho Power.

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[2] As is described in detail in Tom Harvey's testimony, the BCC mine has both a surface and an underground operation.

LOWER OF COST OR MARKET RULE

Q. Please describe the LCM rule.

A. The Commission's LCM rule states:

> The energy utility shall use the following cost allocation methods when transferring assets or supplies or providing or receiving services involving its affiliates: 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.*[3]

This rule appears in Division 27 of the Commission's rules, the division that deals with utility budgets, financing, and accounting.[4]

Q. What is the purpose behind the rule?

A. According to the Commission in Order No. 03-691, the underlying purpose behind the rule is to prevent a regulated utility from subsidizing an affiliate.[5] Because transactions between utilities and their affiliates are not necessarily arms-length transactions, there is a risk that utilities might pay more for goods or services provided by an affiliate than the utility would otherwise pay if it purchased the goods or services on the open market, and funnel the excess profit through the affiliate to the utility's shareholders, who are also by definition shareholders of the affiliate.

Q. You have stated that Mr. Dougherty has misapplied the LCM rule. How has Mr. Dougherty misapplied the LCM rule?

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[3] OAR 860-027-0048(4)(e). (Emphasis added).

[4] *See Re PacifiCorp Request for General Rate Increase*, Docket UE 170, Order No. 05-1050 at 18 (Sept. 28, 2005) ("this rule is an accounting rule").

[5] *See Re Affiliated Transactions for Energy Utilities*, Docket AR 459, Order No. 03-691 at 1 (Dec. 1, 2003).

A. As described above, the LCM rule requires that affiliate transactions be recorded in the utility's books at the lower of cost or market rate. The lower of cost or market rule defines "market rate" as "the lowest price that is *available* from nonaffiliated suppliers for comparable services or supplies."[6] Mr. Dougherty's analysis is flawed because he has incorrectly determined the market rate with reference to coal that is not available to fuel the Plant.

Q. Please explain.

A. In order to perform a proper LCM analysis in this case, the market must be defined by reference to sources of coal that are available to the Company for purchase in lieu of the BCC surface coal. For alternative coal to be "available" as required by the rule, the Company must have the ability to actually purchase that coal in lieu of purchasing the coal from BCC. Although the LCM rule does not define the term "available," Merriam-Webster's dictionary defines it as "present or ready for immediate use <available resources>" or "accessible, obtainable <articles available in any drugstore>."[7] These definitions are both common sense definitions and they conform to the underlying purpose of the LCM rule. The purpose of the LCM rule is to prevent cross-subsidization between a utility and its affiliate. For the rule to be effective in preventing cross-subsidization, the Company must be free to choose to actually purchase coal from another supplier. It is not enough that another source of coal exists if the Company cannot actually supplant its allegedly over-market coal with that other coal.

Q. How has Mr. Dougherty defined the market price?

A. Implicit in Mr. Dougherty's analysis is the recognition that there is no defined market from which the Bridger Plant can buy coal. In the absence of a defined market, Mr. Dougherty assumes a hypothetical market at which the price of delivered coal is equal to the

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[6] OAR 860-027-0048(1)(i) (emphasis added).
[7] *Merriam-Webster Online*, Merriam-Webster Online Dictionary. 2010, <http://www.merriam-webster.com/dictionary/available> (accessed March 5, 2010).

price included in one of the Plant's existing contracts.

Q. Please give an example of a defined market.

A. For electric energy there are energy trading hubs—such as mid-C—that define a market that can be used to compare prices. However, coal is not traded at hubs the way that energy is traded and there is no such market for coal for the Bridger Plant.

Q. You said that Mr. Dougherty assumes a market price based on one of the Bridger's Plant's contracts. Please explain.

A. Mr. Dougherty's Primary and First and Third Alternative analysis define market price by reference to the coal purchased by the Bridger Plant from the Black Butte mine. His Second Alternative Analysis defines the market price by reference to the costs associated with BCC's underground coal. As explained by Mr. Harvey, the Black Butte mine does not have sufficient additional coal available to replace BCC coal. For this reason, the cost of the Black Butte coal should not be relied upon to define the market. Similarly, BCC's underground mine is operating at capacity and cannot replace BCC surface coal.

Q. In data responses Mr. Dougherty states that Black Butte coal is available to the Plant because Bridger already obtains coal from Black Butte. What is your response?

A. Mr. Dougherty's analysis flies in the face of the definition of "available." The mere existence of Black Butte coal to satisfy existing contractual obligations does not suggest that additional amounts are "available" for immediate use or obtainable by the Company. In other words, his analysis reads the word "available" right out of the definition of "market rate."

Q. How should market rate be determined in this case?

A. A market rate in this case would need to consider sources of coal that are actually available for purchase by the Bridger Plant to replace the coal it receives from the BCC surface mine. Once that coal is identified, the market rate must include the total cost of the coal including any transportation necessary to move the coal from its source to the Plant.

Q. Has the Company evaluated the availability of coal that could be considered as a market?

A. Yes. As explained in Mr. Harvey's testimony, coal mines rely on contracts to ensure ongoing viability. Therefore, market or spot coal availability is limited. Generally, to replace the quantities of coal as suggested by Mr. Dougherty, it would require that existing mines expand their operations to additional pits or seams. Expanded operations would require additional capital investments by those mines at costs different than the embedded costs of existing operations as reflected in current contract prices.

Q. Has the Company made any inquiries to quantify the costs of other potential coal sources?

A. Yes. As described in Mr. Harvey's testimony, as the operator of the Plant, PacifiCorp representatives contacted the Black Butte mine and learned that at most the mine, as of February, 2010, had an additional [redacted] tons of coal available to sell to the Plant. This amount is not sufficient to replace the required [redacted] and [redacted] million tons of BCC surface coal.

Q. Mr. Dougherty suggests that the BCC surface costs that could be replaced cost approximately $[redacted] per ton. Has he properly identified the costs that could be displaced?

A. No. Mr. Dougherty included non-displaceable costs associated with total mining operations at BCC as costs that could be saved via shutdown of a portion of BCC's operations.

Q. How does the cost savings associated with discontinuing BCC's surface operations compare to the cost provided by Black Butte for additional tonnage?

A. As described in Mr. Harvey's testimony, the decremental cost of BCC's surface coal is approximately $[redacted] per ton. The cost of replacing that surface coal with Black Butte coal (assuming it has the capacity to actually do so, which it does not) is approximately $[redacted] per ton, including transportation from the mine to the Plant. Thus, even if all other issues—such as the actual availability of Black Butte coal—are ignored, BCC's displaced surface coal costs are lower than Mr. Dougherty's "market rate" coal from Black Butte. In other words, if the Company acted on Mr. Dougherty's adjustment and ceased its surface operation and replaced that coal with coal from Black Butte (again, assuming this was actually possible) it would actually increase the cost to operate the Bridger Plant. Customers would be harmed financially by Mr. Dougherty's adjustment.

MR. DOUGHERTY HAS NOT IDENTIFIED ANY UREASONABLE COSTS

Q. Do you agree with Mr. Dougherty's suggestion that when the Commission approved the affiliated relationship between Idaho Power and IERCO in Order No. 91-567 it reserved the right to review all financial aspects of the arrangement in later ratemaking proceedings?

A. Yes, I do. As Mr. Dougherty's own testimony states, however, the Commission reserved the right to review *for reasonableness* the financial aspects of the relationship.[8] This does not mean that the Commission ordered the application of the LCM rule to all future transactions. My understanding is that this "reasonableness" standard has been used by the Commission to analyze other affiliate transactions as well. For example, I have been advised that in Order No. 02-820, the Commission described its analysis of costs under a generation facilities lease between PacifiCorp and an affiliate and noted:

> This leaves the issue of the standard to be applied when reviewing the cost of the lease. The question is whether the costs of the lease are reasonable, i.e., is the cost of the lease a necessary and ordinary recurring expense. If it is, the costs

[8] *Re Idaho Power Company*, Docket UI 107, Order No. 91-567 at 4 (Apr. 29, 1991) (hereinafter "Order No. 91-567"); Staff/200, Dougherty/5, ll. 8-10.

> are included in rates. If not, the costs are not included in rates.[9]

In a later rate case where the Commission analyzed the costs incurred under the same affiliate lease, I understand that the Commission found the costs were prudently incurred.[10] The Commission's analysis focused on prudence—using its traditional prudence analysis—and not the lower of cost or market.[11]

This reasonableness analysis is especially appropriate here because, as explained later in my testimony, IERCO is not treated as an affiliate for ratemaking so its operations should be subject to the same standard as all of Idaho Power's operations.

Q. Did Mr. Dougherty identify any specific costs that he found to be unreasonable?

A. No. At the conclusion of his testimony he suggests that he identified certain costs that he would have recommended for adjustment in a general rate case review but did not do so here because his LCM adjustment was larger. This "line item cost" analysis is problematic for two reasons. *First*, Mr. Dougherty failed to identify these costs in his testimony and provided absolutely no support for them. Moreover, in a data request Idaho Power specifically asked Staff whether they claimed that any BCC costs were unreasonable. In response, Mr. Dougherty merely reiterated his testimony that the BCC costs were above Black Butte costs and therefore above-market and did not claim that the costs were unreasonable.[12] On that basis alone the Commission should reject any adjustment based on his "line item cost" analysis. *Second*, Mr. Dougherty's analysis here poses a serious

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[9] *Id.* at 7.

[10] *See* Order No. 05-1050 at 22-23.

[11] *Id.* When reviewing the lease, the Commission looked at whether PacifiCorp's actions were reasonable at the time it entered into the lease based on the information it had available at the time.

[12] Staff Response to Idaho Power Data Request No. 1(a) attached as Exhibit 201.

policy concern because it suggests that when analyzing BCC costs the Commission has the option of treating IERCO as an affiliate or a non-affiliate depending on which analysis yields a larger adjustment. Sound public policy would require that the Commission apply either the LCM or the reasonableness standard to BCC's costs, but not neither or both.

POLICY CONCERNS RAISED BY STAFF'S PROPOSAL

Q. Does Mr. Dougherty's proposed adjustment pose any policy concerns for the Company related to its coal procurement strategy?

A. Yes. Mr. Dougherty's proposal to annually examine long-term BCC coal contracts is problematic because it fails to acknowledge the long-term benefits of captive mines, it discourages future investment in captive mines, and it ultimately harms customers. Idaho Power pursues a diversified coal supply strategy. This strategy relies on a combination of fixed price contracts, indexed contracts, and BCC coal to meet the coal supply needs of all of its coal-fired plants. This strategy results in a long-term, stable, and low-cost supply of coal. While these coal contracts may be long-term, Idaho Power conducts regular reviews of its fueling strategies in its effort to reduce fuel costs and optimize customer benefits.

There is no viable spot market for purchasing coal to fuel the Bridger Plant. For this reason, long-term contracts are essential for the Company to continue to provide a cost-effective and reliable source of fuel for the Plant.

If the Commission adopts Mr. Dougherty's adjustment and methodology and the Company is unable to recover reasonable and prudently incurred costs, it will change the Company's coal strategy and mining operations. It would be unreasonable for the Company to continue operations as it has done since the inception of the BCC relationship if there is a significant and real risk that reasonable costs will be consistently disallowed. In essence, the Company's coal operations will shift from a long-term strategy to short-term cost recovery, ultimately at customers' expense.

Q. How does Mr. Dougherty's proposal fail to acknowledge the long-term benefits of captive mines?

A. The use of captive mines has provided long-term benefits to Idaho Power's customers. These benefits include the provision of a reliable and steady source of coal for the Bridger Plant, operational flexibility, and cost-effective coal blending to maximize the efficiency of the Bridger Plant. The BCC mine will likely continue to provide benefits into the future. In Staff's March, 2009, audit of PacifiCorp Staff recognized the advantages of captive mines, noting that, "As a result of potential rising costs, having captive mines may result in an increasing benefit to PacifiCorp's customers."[13]

Mr. Dougherty's proposed adjustment misconstrues the value of the BCC contract by minimizing the long-term benefits received by customers over the life of the agreement. This annual review will create significant problems in terms of long-term planning and is unlikely to benefit customers.

A least-cost fueling strategy for Bridger cannot be based solely on an annual determination of the BCC mine costs relative to other available supply options. The decision to invest in the BCC mining operation was based on long-term analysis extended over the mine's life. Because mine production costs will typically fluctuate more than contract prices, it is unreasonable to limit recovery of production costs in a particular year or test period when the captive operations provide significant savings and benefits to customers over the life of plant's operation. This is especially true here because BCC coal is clearly superior to other supply options over the extended period.

In this case, the least-cost coal supply for the Bridger Plant is a combination of the current Black Butte agreement and the combined BCC surface and underground operations. These provide the optimum coal supply for Bridger. If the Company's coal strategy focused

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[13] Docket UE 207, Exhibit PPL/203, Lasich/5, attached as Exhibit 202.

exclusively on annual determinations of BCC costs, as Mr. Dougherty's adjustment requires, then coal costs will actually increase, as is discussed in detail in Mr. Harvey's testimony.

Q. How does Mr. Dougherty's adjustment discourage investment in captive mines?

A. If captive mines are subject to annual adjustments based on the application of the LCM rule where Mr. Dougherty or another analyst creates a surrogate market price for an unestablished coal market, as proposed here, it will provide a strong disincentive for the Company to enter into long-term coal contracts with affiliates even though these contracts have traditionally provided substantial benefits to customers. When the Commission reviews long-term, non-affiliated contracts for inclusion in rates, it uses a prudence analysis that examines whether the Company acted reasonably when it entered into the agreement.[14] The Commission does not use hindsight to second guess the utility's conduct. If the Commission analyzed these long-term contracts annually, it would create a strong disincentive to enter into a long-term contract because the risk would be too great that future costs would be disallowed based on unknowable future events. This prudence review represents a well reasoned conclusion that it is frequently in customers best interests for utilities to enter into long-term contracts and therefore the Commission will not second guess that decision if it was reasonable when made.

Although the Commission has applied this same prudence analysis to affiliated transactions in the past[15], that is not what Mr. Dougherty is doing here. In proposing an annual LCM adjustment based on annual, rather than long-term cost fluctuations, Mr. Dougherty's is applying a much harsher standard to affiliated interests than would otherwise apply if the contract were between a utility and a non-affiliate. This despite the fact there is no identified cross-subsidization here. This makes the decision to continue a relationship

[14] Order No. 05-1050 at 23.

[15] *See* Order No. 05-1050 at 23.

with a captive mine or begin a new relationship with a captive mine much more difficult. If utilities are discouraged from establishing captive mines, such as BCC, because they receive unfavorable treatment in years when the mine's costs exceed the market (although as Mr. Harvey testifies that is not even the case here) then customers lose out on the numerous benefits these captive mines provide. In the future customers will lose this benefit if the Commission adopts Mr. Dougherty's adjustment because the risk is too great that any long-term benefits are sacrificed by annual adjustments based on the application of the LCM rule.

Q. Does Mr. Dougherty's proposal also jeopardize the Company's diverse coal supply?

A. Yes. As noted above, the Company's coal procurement strategy entails purchasing coal from both BCC and non-affiliate mines. This combination of coal sources serves the important goal of mitigating supply risk by ensuring that the Company is purchasing coal from several sources at any one time. The Bridger Plant has generally relied on two mines for fuel, the BCC mine and the Black Butte Mine. This assures the plant can acquire the continuous coal supply that it requires. For instance, if a major issue arose in BCC's underground operations that limited coal production, the surface operation could be ramped up to help fill the production void. Similarly, if Black Butte sustained a significant production limitation then the BCC integrated surface and underground operations could ramped up to provide for additional coal. This operational flexibility is a key advantage of captive mines and this diversified approach provides the level of reliable and continuous coal supply that is required by a regulated utility in order to meet its obligation to reliably serve its customers' loads. If the Company implements Mr. Dougherty's proposal—ceasing surface operations and increasing purchases from Black Butte or ceasing BCC operations altogether and purchasing exclusively from Black Butte[16]—the Company's well-considered coal strategy will be compromised. This coal strategy has served customers well in the past and will continue to do so in the future.

THE LCM RULE SHOULD NOT APPLY IN THIS CASE

Q. You stated that the LCM rule should not apply in this case to the coal purchases by the Plant from BCC. Why is that?

A. These purchases do not raise the risk of the harm the LCM rule was intended to remedy and so there is no reason to apply it in this case.

Q. What is the purpose behind the LCM rule?

A. As described above, the purpose of the rule is to prevent cross-subsidization between a utility and its affiliate.

Q. In this case is there a risk of cross-subsidization between Idaho Power and BCC?

A. No. The Commission has long recognized that transactions between Idaho Power and BCC pose no risk of cross subsidization because of the unique manner in which the Commission addresses IERCO's (the affiliate that owns BCC) operations. Unlike other utility affiliates, for ratemaking purposes IERCO's operations are merged with those of Idaho Power. As the Commission noted in Order No. 91-567, where the Commission approved the coal sales agreement between BCC and Idaho Power, IERCO is "disregarded as a separate entity for ratemaking purposes."[17] The Commission added:

> 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 ratemaking purposes. Therefore, there is no danger of cross-subsidization between Idaho and IERCO, nor is there any danger of Idaho paying in

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[16] This hypothetical is based on Mr. Dougherty's unsupported assumption that Black Butte has the available capacity to actually replace BCC coal. As Mr. Harvey's testimony makes clear, however, this assumption is wrong.

[17] Order No. 91-567 at 2.

> 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.*[18]

Therefore, the LCM rule should not apply in this case because: (1) for ratemaking purposes, IERCO (and BCC) is not treated as an affiliate at all; and (2) there is no cross-subsidization in this case.

Q. Has Staff alleged that Idaho Power is subsidizing IERCO in this case?

A. No. In fact Mr. Dougherty specifically stated that "there is no cross-subsidization between IERCO and Idaho Power."[19] By Staff's own admission the fundamental purpose behind the LCM rule is not at issue in this case.

Q. Mr. Dougherty suggests that the LCM rule applies to all affiliated interest transactions and it should apply here also. Do you agree?

A. No. I have been advised that the Commission has waived the application of this rule on several occasions. In Order No. 06-016, the Commission waived the rule when Idaho Power sought Commission approval to allow it to provide short-term loans to IERCO.[20] Staff recommended the waiver, even though the interest rate on the loans was not a market rate, noting:

> Since IERCO's net income is included in IPC's net operating income, Staff believes the Commission should allow a cost-based approach to the loans and allow IPC to set interest rates at IPC's short-term borrowing costs and not the lower of cost or market.[21]

This precedent is important because the basis for Staff's recommendation, and the Commission's ultimate adoption of that recommendation, applies here with equal force—

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[18] Order No. 91-567 at 2 (emphasis added).

[19] Staff/200, Dougherty/5, l. 30 – 6, l. 1.

[20] *Re Idaho Power Company Application for Authority to Provide Short-Term Loans to Idaho Energy Resources Co.*, Docket UI 244, Order No. 06-016 at 3 (Jan. 17, 2006) (hereinafter "Order No. 06-016").

[21] Order No. 06-016 at App. A at 4.

IERCO is not an affiliate for ratemaking purposes so the LCM rule should not apply to transactions between Idaho Power and IERCO.

In Order No. 91-513, the Commission approved the mining contract between PacifiCorp and Energy West Mining Company ("EWMC") on a cost-based approach rather than the lower of cost or market.[22] The Commission found that EWMC was established such that it could not earn a profit (like BCC) and found that it was unlikely a third-party could provide the services at a lower cost. The Commission found:

> This cost-based approach and the limitation of EWMC's activities to those arising under the contract minimize the likelihood of cross-subsidization. Due to recent reductions in operating costs at EWMC's Utah mines Pacific is purchasing coal at or below market prices. Through the rate-making process, the Commission can ensure that Oregon utility customers do not pay unreasonable expenses. The Commission concludes that the agreement is fair and reasonable and not contrary to the public interest.[23]

Here, BCC also performs only activities arising under a contract and that contract is very similar to the one the Commission addressed in Order No. 91-513.

Q. Has the Commission ever waived the LCM rule with respect to BCC coal?

A. Yes. As Staff noted in their March 11, 2009, "Staff Audit Report of PacifiCorp":

> Commission orders concerning affiliated interest contracts with Bridger (Order No. 01-472, UI 189) and Energy West (Deer Creek, Order No. 91-105, UI 105) allow for a cost-based pricing of coal from these affiliates. *This is an approved departure from OAR 860-027-0048, Allocation of Costs by an Energy Utility, which normally requires the lower of cost or market standard when a utility is purchasing goods or services from an affiliate.*[24]

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[22] *Re PacifiCorp*, Docket UI 105, Order No. 91-513 at 3 (Apr. 12, 1991).

[23] Order No. 91-513 at 2.

[24] Docket UE 207, Exhibit PPL/203, Lasich/5 (emphasis added), attached as Exhibit 202.

Based on these past waivers and the unchanged circumstances surrounding coal sourcing for the Bridger Plant, the Commission should again waive the rule as it has in the past.

Q. If the LCM rule does not apply to the coal purchases in this case, how should the Commission analyze BCC's costs?

A. As discussed above, BCC's operations—because they are merged with those of Idaho Power for ratemaking—should be analyzed based on the same standards as all other Idaho Power costs and contracts. If the costs are reasonable and the Company was prudent in entering into the contract with BCC then the Company should be allowed to recover those costs in rates.

Q. Doesn't the Commission's Order No. 91-567 also require the Company to notify the Commission of any material changes in costs that occur?

A. Yes it does. Although the Company has not filed a separate and distinct case solely for the approval of the contract amendments/restatements, the costs resulting from those amendments/restatements have been brought before both the Idaho and Oregon Commissions on numerous occasions for review, during both general rate cases and annual power cost cases, and on each occasion the respective Commissions have reviewed and approved the same.

Q. Mr. Dougherty suggests that an accounting principle, EITF 04-6, may be responsible for the annual fluctuations in BCC coal costs. Do you agree?

A. Yes, to some extent the accounting principle does account for the annual fluctuations. However, in this case the impact of this principle is fairly small.

Q. Are there difficulties with applying the LCM test when coal costs are accounted for under the EITF 04-6 accounting standard?

A. Yes. While the annual fluctuation in cost resulting from the EITF standard is relatively small, the application of the LCM rule does not align well with this method of accounting. The EITF accounting standard requires BCC to book the costs of overburden removal in the month that those costs are incurred. Because the overburden removal cost can vary from year to year, independent of actual coal production, the unit cost of coal can be impacted. Theoretically, in years when the booked costs of overburden removal do not align with the corresponding coal removal and production, the unit cost of coal could be artificially inflated or deflated for that period. Therefore, under this approach the Company would recover its prudently incurred costs only in years when the unit price is artificially deflated due to the EITF standard. This puts the Company in a "heads you win, tails I lose" situation where it is not allowed an opportunity to recover prudently incurred costs that are necessary to continuously and reliably serve its customers.

Q. Mr. Dougherty suggests that regardless of the impact of the accounting principle, it applies equally to affiliated and non-affiliated mine and therefore it is immaterial. Do you agree?

A. No. This comparison is invalid because non-affiliated mines, such as Black Butte, do not sell their coal to the Plant based solely upon their operating cost. EITF 04-6 deals with how a mine accounts for its costs, not how that mine contracts to sell its coal. Because non-affiliated mines do not sell their coal to the Plant based upon their cost, application of this principle can have a disproportionate impact on affiliated transactions and provide further disincentive to a utility choosing to enter into this type of relationship.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Greg Said

Staff Response to Idaho Power Data Request 1(a)

March 17, 2010

March 8, 2010

TO: Lisa Rackner
Idaho Power Company

FROM: Michael Dougherty, Program Manager
Corporate Analysis and Water Regulation

Ed Durrenberger, Senior Utility Analyst
Electric Rates and Planning

OREGON PUBLIC UTILITY COMMISSION
UE 214
Idaho Power's First Set of Data Requests to OPUC
Due March 8, 2010
Data Request Nos. 1-7

Request:

1. See Staff/200, Dougherty/5, lines 8-10.
   a. Does Staff assert that BCC coal costs are unreasonable? If so, please provide all justifications for this position.

   b. Does Staff assert that the BCC coal costs reflected in the Company's filing do not represent the actual cost of mining the coal and delivering it to the plant?

Response:

a. Throughout testimony, Staff asserts:

- BCC is an affiliate of Idaho Power;
- OAR 860-027-0048, *Allocation of Costs by an Energy Utility*, applies to the transfer pricing between BCC and Idaho Power;
- BCC weighted cost per ton is higher than the third party delivered cost per ton; and
- As a result, BCC coal costs in rates must be the lower of cost or market.

b. No. Staff asserts that the affiliate's coal costs are higher than the market cost.

Idaho Power/202
Witness: Greg Said

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Greg Said

Docket UE 207, Exhibit PPL/203, Lasich/5

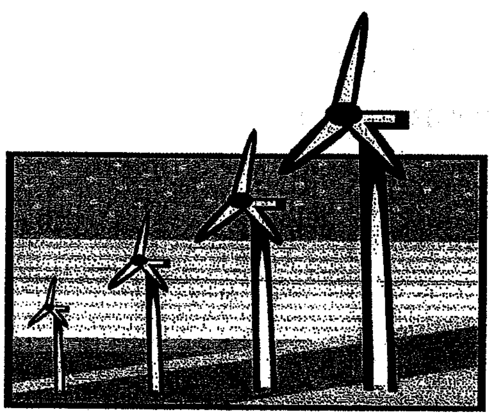
March 17, 2010

Staff Audit Report of

PacifiCorp

Audit Number: 2008-002

March 11, 2009



Audit team: Dustin Ball (Lead Auditor)
Michael Dougherty
Marion Anderson

Prepared by: Dustin Ball

Corporate Services/Cost Allocation Manual

Pursuant to OAR 860-027-0048, PacifiCorp provided Staff a Cost Allocation Manual (CAM) as an attachment to its 2007 Affiliated Interest Report. Staff reviewed the content and format of the CAM and believes that PacifiCorp has adequately addressed its cost allocation methods.

Coal Purchases from Affiliates

PacifiCorp purchases coal from certain affiliates, Bridger Coal Company, Energy West Mining Company, and Trapper Mining Company. The Bridger Mines provides coal to the Jim Bridger plant, of which PacifiCorp owns 66.7 percent. The Jim Bridger plant is located in Wyoming. According to the Company, the transition of Jim Bridger Coal Company from surface mining operation to a combined underground/surface mining operation has resulted in an increase in costs and a shift in cost drivers. As a result in the change in operation, coal costs from Jin Bridger have increased.

Energy West Mining Company's Deer Creek Coal Company (underground mining method) provides coal for the Company's Carbon, Hunter, and Huntington Plants, which are located in Utah. According to PacifiCorp, coal costs have increased from 2006 to 2008 due to a number of factors including labor and benefit costs, materials and supplies, mine maintenance, and professional services.

PacifiCorp is also a minority owner of Trapper Mining Inc. (21.4 percent). Trapper Mining Inc. provides coal to PacifiCorp's Craig Plant, which is located in Colorado. According to PacifiCorp's 10-K, the Craig Plant is supplied from coal produced from a surface mining operation.

The following tables shows Bridger Coal Company (Underground/Surface), Deer Creek Coal Company (Underground), and Trapper Mining Coal Company (Surface) coal costs for 2006 through 2008. The table also for illustrative purposes shows coal costs for PacifiCorp coal plants not supplied by affiliates. Unless specified, the coal costs do not include transportation costs.

Table 25 – Coal Costs, 2006 - 2008

	2006	2007	2008	Change 2006 - 2008
Coal Purchased from Affiliates				
Bridger Coal – Wyoming (Combined)	$20.77	$23.59	$29.37	41.41%
Deer Creek Coal – Utah (Carbon, Hunter, Huntington - Underground)	$23.93	$26.27	$25.08	4.81%

Trapper Coal Base – Colorado (Craig - Surface)	$22.68	$24.43	$25.57	12.74%
Trapper Coal Spot – Colorado (Craig - Surface)	$22.50	$20.60	$29.88	32.8%

Coal Purchased from Third Parties				
Coal supplied to Cholla - Arizona (Surface)	$24.05	$24.24	$27.52	14.43%
Dave Johnston – Wyoming (Surface)	$5.34	$5.83	$7.14	33.71%
Dave Johnston – Wyoming with Transportation	$9.99	$10.52	$12.09	21.02%
Wyodak – Wyoming (Surface)	$10.59	$10.81	$11.49	8.50%
Naughton – Wyoming (Surface)	$25.04	$27.46	$26.86	7.27%
Colstrip – Montana (Surface)	$14.46	$15.80	$17.27	19.43%
Hayden – Colorado (Combined)	$31.38	$33.43	$34.03	17.27%
Hayden – Colorado with Transportation	NA	NA	$36.80	NA

The following table highlights market prices.

Table 26 - DOE/EIA 2007 Info Average sale price ($ per Short Ton)

State	2006 Underground	2006 Surface	2007 Underground	2007 Surface
Colorado	$24.10	$24.70	$24.91 (Total)	Not listed
New Mexico	$29.15 (Total)	Not Listed	$29.91 (Total)	Not listed
Utah	$24.98	Not listed	$25.69	Not listed
Wyoming	Not Listed	$9.03	Not Listed	$9.67 (Open) 13.62 (Captive)

** Information received from PacifiCorp based on Platt's indicates that 2008 average Colorado coal price was $34/ton, a significant increase from the 2007 level. Additionally, 2008 average Utah coal price was $28.41, also a significant increase from the 2007 level.*

The DOE/EIA prices exclude silt, culm, refuse bank, slurry dam, and dredge operations. The DOE/EIA did not include a price for underground operations in Wyoming (withheld to avoid disclosure), but the average 2007 market price for underground operations in Utah was listed at $25.69 and the average 2007 market price for total operations in Colorado was listed as $24.91.

The market prices in these neighboring states are comparable to PacifiCorp's 2007 costs for underground and combined operations (Bridger - $23.59; and Deer Creek - $26.27). The 2008 Deer Creek cost of $25.08 reflects a $1.19/ton decrease in cost from the 2007 level resulting in considerably lower than market levels ($28.41) in 2008. As noted by FERC Market Snapshot Regional Coal Spot Prices, Utah and Colorado coal prices have risen sharply in 2008.

In a response to a Staff data request, PacifiCorp stated that all power plants are typically designed and constructed to consume a typical range of coals. As an example, the Hayden Plant consumes Colorado coals, which are normally bituminous, while other plants (Jim Bridger, Dave Johnston, Wyodak, and Colstrip) consume sub-bituminous coals. The following table highlights the Btu/lb of coal used by PacifiCorp plants

Table 27 – Heat Content of Coals used by PacifiCorp Plants

Mines	Btu/lb
Hayden (Colorado)	10,500 – 11,300 Btu/lb
Dave Johnston, Wyodak and Colstrip (PRB)	8,000 – 8,800 Btu/lb
Jim Bridger (Green River Basin – Wyoming)	9,200 – 10,000 Btu/lb

According to its website, the DOE/EIA lists Powder River Basin (PRB) spot cost per short ton, as of November 7, 2008, as $14.50. The website does not distinguish between underground and surface operations as there appears to be a lack of historical pricing for Wyoming underground operations. (Bridger is currently the only underground mine operation in Wyoming.) However, it should also be noted that the cost of PRB coal is expected to increase due to rising costs of Appalachian coal. According to Mineweb.com[9]:

> Soaring demand for coal and spiking prices should open new markets at home -- and to a lesser extent overseas -- for low-cost, low-sulfur coal from Wyoming's Powder River Basin, providing a boost for the miners that produce it and the railroads that move it.

The article also points out:

[9] http://www.mineweb.com/mineweb/view/mineweb/en/page38?oid=54526&sn=Detail

> PRB coal is the world's cheapest source of electricity," said Dan Scott, director of equity research at investment bank Dahlman Rose. "In today's market, that creates interesting opportunities for miners and the railroads hauling the coal.

As a result of potential rising costs, having captive mines may result in an increasing benefit to PacifiCorp customers. This is not a foregone conclusion and costs and cost trends would need to be examined during subsequent rate filings.

Transfer Pricing

Commission orders concerning affiliated interest contracts with Bridger (Order No. 01-472, UI 189) and Energy West (Deer Creek, Order No. 91-105, UI 105) allow for cost-based pricing of coal from these affiliates. This is an approved departure from OAR 860-027-0048, Allocation of Costs by an Energy Utility, which normally requires the lower of cost or market standard when a utility is purchasing goods or services from an affiliate.

ORS 757.495, Contracts involving utilities and persons with affiliated interests, requires the Commission to approve the contracts if the Commission finds that the contracts are fair and reasonable and not contrary to the public interest. In both the Bridger and Energy West contracts, the Commission found that the contracts were fair and reasonable and not contrary to the public interest.

However, concerning approval of affiliated interest contracts, the Commission does not need to determine the reasonableness of all the financial aspects of the contract for ratemaking purposes. The Commission can reserve that issue for a subsequent proceeding. The subsequent proceeding in this case would be the Company's TAM or general rate filing.

Concerning transfer pricing in UI 189, Staff's memo states:

> 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.

Deer Creek Mine

Based on a comparison, the average 2007 market price in Utah (underground) of $25.69 was lower than PacifiCorp's coal costs concerning Deer Creek underground ($26.27). However; as previously mentioned, the 2008 Deer Creek cost of $25.49 reflects a decrease in costs from the 2007 level resulting in slightly lower than market levels ($25.69). If 2008 Deer Creek costs are actually determined to be below market and maintained at below market, this would result in a benefit to customers.

Trapper Mining

Concerning Trapper Mining, the 2007 market price for total operations in Colorado ($24.91) is higher than the Trapper Mining 2007 cost for base ($24.43) and spot ($20.63) purchases. Additionally, 2008 third-party coal costs for PacifiCorp's Hayden Plant in Colorado was significantly higher ($34.03) than the Trapper Mining 2008 cost for base ($25.57) and spot ($29.88) purchases. As a result, Trapper Mining costs actually appear are clearly below market cost, which results in a benefit to customers.

Bridger Coal

As previously mentioned, Bridger is a combined surface/underground mining operation. The following table highlights the change in operation of Bridger from a predominantly surface operation to a predominantly underground operation from the 2006 through 2008 time period.

Table 28 – Bridger Mining Operations

	2006	2007	Through September 2008
Surface Operations – Tons (000)	5,646.0	3,139.4	1,745.0
Surface Operations - $/Ton	$18.490	$18.354	$24.467
Underground Operations – Tons	422.3	2,644.9	2,471.8
Underground Operations – $/Ton	$51.24	$29.812	$34.185

The 2008 Bridger combined underground/surface cost ($28.34) as well as underground cost ($34.19) are comparable to the 2008 underground mining for Utah ($28.4) and Colorado ($34.00). The Bridger 2008 surface coal cost ($24.467) is considerably higher than two other PacifiCorp's Wyoming plants (Dave Johnston ($12.09 with transportation), Wyodak ($11.49), but actually lower than coal cost at Naughton ($26.86). It should be noted that Bridger is located in Southwest Wyoming's Green River Basin (GRB). According to information furnished by PacifiCorp, there are only three coal mines operating in the GRB.

Additionally, it should be noted that PacifiCorp Bridger costs are higher than the Wyoming overall market costs. Unfortunately, because Bridger is the only underground mining operations in Wyoming, comparative cost studies can not be made for Wyoming underground operations. In addition, Bridger coal is mined from GRB and requires a higher heat content than PRB coal, which also affects any straight cost comparison.

Because PRB coal is the next logical coal supply for Bridger, associated transportation costs to transport PRB coal to Bridger could possibly make this option economically infeasible. With that said, the affiliated interest statute allows for a review of costs that go into rates.

As a result, rate case staff should examine 2008 comparable coal costs to determine if the 2008 Bridger costs are in the range of 2008 comparable underground mining costs for the GRB region. If Bridger costs show a trend of exceeding comparable market costs, staff may be required to review the transfer pricing in UI 189 concerning Bridger in order to protect the public's interest.

In addition, during a rate case or TAM review, utility staff should recommend that Bridger coal costs be adjusted for the lower of cost or market for ratemaking. Again, the affiliated interest order concerning Bridger (Commission Order No. 01-472, UI 189) includes a condition that states:

> The Commission reserves the right to review for reasonableness all financial aspects of this arrangement in any rate proceeding or alternative form of regulation.

Staff Recommendations:

10. Staff should examine 2008 comparable coal costs to determine if the 2008 Bridger costs are in the range of 2008 comparable underground mining costs for the Green River Basin region. If Bridger costs show a trend of exceeding comparable market costs, staff may be required to review the transfer pricing in UI 189 concerning Bridger in order to protect the public's interest. *(Further investigation during the rate case)*

11. In future filings, Staff should recommend that Bridger coal costs be adjusted for the lower of cost or market for ratemaking. *(Further investigation during the rate case)*

Review of Affiliate Coal Costs

Staff examined account line detail of affiliate coal costs. The following comments are relevant concerning PacifiCorp's coal costs included in rates.

Bridger Coal

Management/Supervisory Overtime

Bridger experienced a significant increase in Management/Supervisory overtime costs from $117,838 in 2006 to an annualized amount of $448,908 in 2008. Audit Staff is not aware of any recent rate orders that have allowed overtime for management/supervisory personnel. The Oregon-allocated amount equals approximately $80,499 ($448,908 x 66.67 percent x .268974 allocation). As a result of supervisory overtime costs, in future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs

Bargaining/Temporary Overtime
Bridger experienced a significant increase in Bargaining/Temporary overtime costs from $6,866,573 in 2006 to an annualized amount of $10,537,424 in 2008 (57.3 percent). This 2008 overtime amount represented approximately 31 percent of Bargaining/ Temporary 2008 annualized total (regular plus overtime) pay. Bridger shifted from surface to combination underground/surface mining operation. As a result, Bridger increased full-time equivalents (FTE) from 288 to 353.

The following table examines FTE and regular/overtime wages for Bargaining/Temporary employees.

Table 29 – Bridger Bargaining/Temporary FTE and Wages (2008 Annualized)

		Per Employee
Total FTE	353	
Total Regular	$16,878,441	$47,814
Total Overtime	$10,537,424	$29,851
Total	**$27,416,218**	**$77,665**

As a result of the high overtime costs, in future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Incentives
Bridger's 2008 annualized incentive costs equal approximately $878,067. Following the same methodology for ratemaking, Staff would recommend a 50 percent adjustment to incentives. The Oregon-allocated amount equals approximately $78,730 ($878,067/2 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine incentives in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Health Care Costs
According to PacifiCorp, Bridger Coal health care benefit programs target a 90/10 sharing arrangement for bargaining employees and programs ranging from a 90/10 to 74/26 for management employees. In the most recent energy utility rate case (UE 197), Staff recommended an 85/15 sharing of premium costs. Bridger's 2008 annualized health costs were $4,417,512. At an 85/15 sharing, these costs would be approximately $4,172,095. The Oregon-allocated amount

equals approximately $44,009 ($245,417 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine health care costs in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Employee - Meals
Bridger experienced $43,564 (annualized to $58,085) in meals and entertainment expenses. During a rate case, Staff will normally recommend a 50 percent sharing between customers and shareholders. This is a fair approach that somewhat mirrors the policy associated with bonuses (50 percent sharing between customers and shareholders) and the handling of these expenses for income tax purposes. For income tax purposes, the amount allowable as a federal income tax deduction for business meal and entertainment is generally limited to 50 percent of the total expense. The Oregon-allocated amount equals approximately $5,208 ($58,085/2 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine meals in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Donations
Bridger's 2008 annualized costs for donations are approximately $2,933. These costs should be disallowed because the Commission has not allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. These expenses are discretionary and are not required to provide safe and adequate service to customers. In addition, Commission policy does not require customers to support causes in which they do not believe.[10] The Oregon-allocated amount equals approximately $526 ($2,933 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine donations in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Fines and Citations
Bridger's 2008 annualized costs for fines and citations are $203,388. Customers should not be required to pay for fines and citations incurred by Bridger. The Oregon-allocated amount equals approximately $36,473 ($203,388 x 66.67 percent x .268974 allocation). In future rate filings, assigned Staff should examine fines and citations in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

[10] OPUC Order 87-406 states at pp. 40-41, "Since community affairs expenditures are discretionary, the funds could be retained by the business's owners. . . .Owners of unregulated businesses, rather than their customers, make community affairs contributions." Also see Order 91-186 at 16.

Other O&M
Because of the change in operations, Bridger experienced increased costs in many O&M line items and incurred other costs not experienced during surface mining operations. Audit Staff recommends that during future rate filings, Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs that should not be included in rates.

Staff Recommendations concerning Bridger costs:

12. In future rate filings, assigned Staff should examine mining wage/salaries, overtime costs, health care costs, incentive, donations, meals and entertainment, and fines in the same method as Company wages are analyzed during rate cases and make the appropriate adjustments to coal costs.

13. In future rate filings, assigned Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs.

Deer Creek Mine

Staff examined account-line detail for the Deer Creek Operations. The following comments are relevant concerning PacifiCorp's coal costs in rates.

Management/Supervisory Overtime
Deer Creek experienced a significant decrease in Management/Supervisory overtime costs from $351,306 in 2006 to an annualized amount of $182,525 in 2008. Although this is a decrease in costs, Audit Staff is not aware of any recent rate orders that have allowed overtime for management/supervisory personnel. The Oregon-allocated amount equals approximately $49,094 ($182,525 x .268974 allocation). In future rate filings, assigned Staff should examine supervisory overtime in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Bargaining Overtime
Deer Creek experienced a increase in bargaining overtime costs from $2,350,962 in 2006 to an annualized amount of $2,526,102 in 2008. This 2008 overtime amount represented approximately 18.4 percent of Bargaining 2008 annualized total (regular plus overtime) pay. The following table examines FTE and regular/overtime wages for bargaining employees.

Table 30 – Deer Creek Bargaining FTE and Wages (2008 Annualized)

		Per Employee
Total FTE	278	
Total Regular	$11,217,881	$40,352
Total Overtime	$2,526,102	$9,087
Total	**$13,744,261**	**$49,439**

As can be seen from the above table, total pay of Deer Creek bargaining personnel ($49,439) is approximately 63.7 percent of total average bargaining pay of Bridger Coal ($77,655). This difference is primarily a result of lower overtime payments and reflects a considerable savings for ratepayers. In future rate filings, assigned Staff should examine mining wage/salaries in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Incentives

Deer Creek's 2008 annualized incentive costs equal approximately $1,230,000. Following the same methodology for ratemaking, Staff would recommend a 50 percent adjustment to incentives. The Oregon-allocated amount equals approximately $165,419 ($1,230,000/2 x .268974 allocation). In future rate filings, assigned Staff should examine incentives in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Health Care Costs

According to PacifiCorp, Deer Creek's health care benefit programs in 2007 and 2008 ranged from 85/15 to 80/20 cost sharing. The option of a 90/10 cost sharing arrangement for management employees was implemented in 2008. All other plans have a 74/26 cost sharing arrangement in 2008. In the most recent energy utility rate case (UE 197), Staff recommended an 85/15 sharing of premium costs. In future rate filings, assigned Staff should examine health care costs in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Meals and Entertainment

Deer Creek experienced $33,463 (annualized to $44,617) in meals and entertainment expenses. As previously mentioned, during a rate case, Staff will normally recommend a 50 percent sharing between customers and shareholders. The Oregon-allocated amount equals approximately $6,000 ($44,617/2 x .268974 allocation). In future rate filings, assigned Staff should examine meals in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Club/Organization Membership and Expense

Although Deer Creek had costs in 2006 and 2007 for this line item, PacifiCorp reported $0 for 2008. Normally, this is a cost item that staff would examine in more detail; however because there is no cost in 2008, a further review is not necessary. In future rate filings, assigned Staff should examine membership expenses in the same method as analyzed during rate cases and make the appropriate adjustments to coal costs.

Mining Services

In 2008, Deer Creek Mine experienced $2.33 million in mining services. According to PacifiCorp, these services are for major equipment overhauls performed away from the mine at vendor facilities. During PacifiCorp's subsequent rate filings these costs should be reviewed in detail to determine if some of these expenses are more correctly capitalized. This is because replacements and overhauls generally have the effect of increasing the service potential of an asset by either improving the asset's efficiency or extending the asset's economic useful life. As a result, the costs of replacements and overhauls are capitalized.[11]

Other O&M

Audit Staff recommends that during future rate filings, assigned staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs. Concerning Deer Creek, Audit Staff notes considerable increase in professional services, management fees, royalties, and fuel from 2007 to 2008.

Staff Recommendations concerning Deer Creek costs:

14. In future rate filings, assigned Staff should examine mining wage/salaries, overtime costs, health care costs, incentive, donations, meals and entertainment, and membership expenses in the same method as Company wages are analyzed during rate cases and make the appropriate adjustments to coal costs.

15. In future rate filings, assigned Staff should examine line item costs in order to trend costs and to highlight any possible extraordinary costs.

Trapper Mining

Because PacifiCorp is a minority owner of Trapper Mining, PacifiCorp did not have detailed line item costs for Trapper Mining. However, as previously mentioned, Trapper Mining costs were lower than the listed DOE/EIA 2007 market costs. As a result, PacifiCorp is actually receiving goods at the lower of cost or market.

Coal Transportation

PacifiCorp's Cholla, Dave Johnston, and Hayden Plant all received transported coal. The following table examines transportation cost per ton.

[11] Munter – Radcliffe, *Applying GAAP and GAAS, Depreciable and Intangible Assets*, Matthew Bender & Co., Inc. page 10-21.

Table 31 - Coal Transportation Costs

Plant	2006	2007	2008	Percent Change 2007 - 2008
Cholla – Arizona (Coal from New Mexico and Montana	$4.91*	$7.47	$7.97	6.69%
Dave Johnston – Wyoming (Coal from Wyoming)	$4.65	$4.68	$4.94	5.26%
Hayden – Colorado (Coal from Colorado)	NA**	NA	$2.76	NA

** Cholla's 2006 costs were significantly lower than subsequent years due to a $3 million credit applied to Cholla in January 2006.*

*** Prior to 2008, PacifiCorp did not separate transportation costs from coal costs at the Hayden plant.*

Because PacifiCorp's Cholla plant is located in Arizona, higher transportation costs would be reasonably expected. Because of the low cost of coal being supplied to the Dave Johnston plant ($7.14 in 2008), transportation costs actually account for approximately 40.4 percent of total coal costs. Even with transportation costs, the Dave Johnston plant had the second lowest 2008 coal costs for PacifiCorp plants at $12.07 per ton. Only the Wyodak plant, supplied by the Wyodak mine and not requiring transportation, had lower costs at $11.49 per ton.

As previously mentioned, PacifiCorp has two Commission approved affiliated contracts with Burlington Northern Santé Fe Railroad (BNSF). Berkshire-Hathaway currently owns 17 percent of BNSF. PacifiCorp has long-term coal transportation contracts with BNSF, including indirect payments to a generation plant that is jointly owned by PacifiCorp. The transportation contacts were approved by the Commission in Order No. 07-323 (UI 269), dated July 27, 2007. BNSF provides transportation services from:

1. Various coal mines in the Wyoming Powder River Basin to PacifiCorp's David Johnston Steam Plant (David Johnston); and

2. Various coal mines in Wyoming, New Mexico, and Montana to PacifiCorp's Cholla Generating Station (Cholla).

These agreements were executed as third-party agreements prior to PacifiCorp becoming a subsidiary of MEHC. This type of service is provided pursuant to a contract filed and approved by the Surface Transportation Board (STB)[12] would generally not require Commission approval; however, PacifiCorp and MEHC agreed to a different affiliate transaction standard as part of PacifiCorp's acquisition by MEHC. PacifiCorp pays approximately $30 million per year for services under the Agreements with BNSF. PacifiCorp records most of the charges related to the BNSF agreements in FERC Account 501, Fuel.

Operations and Maintenance Expenses

The following table presents O&M expenses (FERC accounts 500-598) for 2006 and 2007:

Table 32 - O&M Cost Comparison

	2006	2007	Percentage Change 2006-2007
Labor	123,864,786	100,446,457	-18.9%
Non-Labor	432,179,061	572,124,600	32.4%
Total O&M	556,043,847	672,571,057	21.0%

The overall increase is higher than the Consumers Price Index for All Urban Consumers of 2.8 percent for the period and is largely attributable to two areas – (1) higher gas costs and (2) plant additions. An account comparison was made and there were 15 instances of year-to-year variances greater than 10 percent. The company provided satisfactory explanations for these increases. The distortions due to singular accounting occurrences i.e. out-of-period charges were also itemized.

Customer Service

The company stated that there is a ten-year technology improvement plan. There are four current deliverables:

1. Customer correspondence improvement project – template improvement as to location and clarity.
2. Automated outage customer call back program – customizing notification and follow up service restoration.
3. Computer telephony integration and interactive voice response systems – symmetry between account information displayed online and phone accessible and multiple phone match screens.

[12] The Surface Transportation Board (STB) was created in the Interstate Commerce Commission Termination Act of 1995 and is the successor agency to the Interstate Commerce Commission. The STB is an economic regulatory agency that Congress charged with the fundamental missions of resolving railroad rate and service disputes and reviewing proposed railroad mergers. The STB is decisionally independent, although it is administratively affiliated with the Department of Transportation. (www.stb.dot.gov)

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-01

IDAHO POWER COMPANY

ATTACHMENT NO. 3

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 214

IN THE MATTER OF)
IDAHO POWER COMPANY'S)
2010 ANNUAL POWER COST UPDATE)
)
)
)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

TOM HARVEY

March 17, 2010

REDACTED

Q. Please state your name and business address.

A. My name is Tom Harvey. My business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as Manager-Joint Projects.

Q. Please describe your educational background.

A. I have a Bachelor of Business Administration-Business Management from Boise State University.

Q. Please describe your business experience with Idaho Power.

A. I have been the Manager-Joint Projects for four months. In this position I supervise Idaho Power's interests in the Jim Bridger, North Valmy, and Boardman coal-fired power plants. I also manage Idaho Power's interests in the Bridger Coal Company ("BCC") and coal supply acquisition/fuel management. I am a member of the Bridger Coal Management Committee which is comprised of two Idaho Power and two PacifiCorp employees. This committee directs Bridger Coal on both short and long-term strategy issues, reviews current operations and approves all capital and O & M expenditures. With respect to the Jim Bridger Plant ("Bridger Plant" or "Plant") I work with PacifiCorp on the fueling strategy and oversee Idaho's minority share of the overall operations of the Plant. Prior to my appointment to my current position, I served as Idaho Power's Fuels Management Coordinator from 1985 to 2009. In this position I was responsible for coal supply acquisition/fuel management for Idaho Power's interest in the coal-fired power plants and Bridger Coal Company. Prior to 1985 I worked in Idaho Power's power supply and plant accounting departments. Beginning with the Fuels Management Coordinator position, I have worked closely with PacifiCorp to coordinate fuel deliveries and coal purchase strategy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the coal cost adjustment proposed by Staff witness Michael Dougherty.[1] Company witness Gregory Said's testimony responds to the policy issues raised by Mr. Dougherty's proposal while my testimony addresses the technical and factual issues raised by his adjustment.

Q. Please describe Mr. Dougherty's proposed adjustment.

A. Mr. Dougherty's adjustment focuses on the coal costs for the Bridger Plant. As I will discuss in more detail below, Idaho Power co-owns with PacifiCorp both the Bridger Plant, and its associated mining operation, BCC. The Plant is run primarily on coal from BCC's surface and underground mining operations, supplemented by coal purchased from the Black Butte Mine ("Black Butte"). Mr. Dougherty claims that the costs of the coal purchased by the Company for the Bridger Plant from BCC exceeds the market rate for coal and therefore violates the Public Utility Commission of Oregon's lower of cost or market ("LCM") rule.[2] To remedy this perceived violation, Mr. Dougherty replaces the cost of BCC's surface coal—which is more expensive to produce than the underground coal—with the cost of the Black Butte coal. Accordingly, Mr. Dougherty proposes a $15 million system-wide adjustment.

Q. Please summarize the Company's response.

A. My testimony, together with the testimony of Gregory Said, will demonstrate that Mr. Dougherty's LCM analysis is flawed in two respects: *First*, Mr. Dougherty improperly calculates the cost of BCC surface coal for comparison to market alternatives. In order to produce a meaningful result the LCM analysis must consider the decremental cost

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[1] Staff/200.

[2] The LCM rule states that for transactions between a regulated utility and an unregulated affiliate, any goods sold by the affiliate to the utility must be priced at the lower of the cost to the affiliate to produce the good or the market rate to purchase a comparable product from a non-affiliated supplier.

(or, avoided cost) of the BCC surface coal. When the decremental cost is considered, it will demonstrate that the cost that the Company will avoid if it replaces the BCC surface coal with coal from Black Butte is actually *less* than it would pay for the replacement Black Butte coal—assuming it could be obtained. *Second,* Mr. Dougherty errs in setting the "market price" by reference to the cost of Black Butte coal—which, as I will explain, is not available in sufficient quantities to replace BCC surface coal. The contract price the Company pays for Black Butte coal does not constitute the "market" price at which the Company could obtain an alternative coal supply for the Bridger Plant. I will show that when the cost of coal that may be available to replace the BCC surface coal is considered, it is clear that, overall, BCC coal is the lowest cost resource.

Finally, I will describe the non-price benefits of the BCC contract to Idaho Power's customers, which include the use of BCC coal in the blending process to produce the most efficient coal for the Bridger Plant and the flexibility to use BCC operations as a hedge against production decreases at Black Butte.

BRIDGER PLANT AND BCC

Q. Please describe the Bridger Plant.

A. The Bridger Plant is a coal-fired electric generation facility consisting of four units with a unit nameplate net capacity of 530 megawatts ("MW") each. The plant is jointly owned by PacifiCorp and Idaho Power and is located in southern Wyoming, in the Green River Basin ("GRB"). PacifiCorp is a two-thirds majority owner and operates the Plant. Idaho Power owns the remaining one-third minority interest. At normal operation the Plant burns approximately [redacted] tons of coal annually.

Q. Is the Bridger Plant run continuously?

A. Yes. Large coal-fired generation plants, such as the Bridger Plant, are less expensive to operate than other forms of generation, and conversely, are expensive to shut down and restart. For these reasons, the units are normally run continuously and shut down only for planned maintenance, unplanned outages, or emergencies. Because these resources generate on a continual basis it is essential that they have access to a continuous and reliable source of coal. The Plant's continuous operation dictates, in part, the coal procurement strategy for the Company. As described in more detail in Mr. Said's testimony, the Company's coal strategy relies on a combination of indexed contracts and BCC coal to meet the coal supply needs of the Bridger Plant. A key component of this strategy is the use of BCC's captive mine and long-term contracts to produce a long-term, stable, and low-cost supply of coal. For the Bridger Plant this strategy is mindful of the lack of a spot market for coal purchases in the GRB.

Q. What are the sources of the Bridger Plant's coal?

A. The Bridger Plant was designed and constructed as a "mine-mouth" plant, which means it is physically located next to the coal mine that supplies the majority of its coal. The adjacent mine is owned by BCC, which is jointly owned by PacifiCorp and Idaho Power, on the same two-thirds/one-third basis as the Bridger Plant.[3] This arrangement ensures that the Plant has access to a continuous and reliable supply of coal. BCC provides the Plant with approximately [redacted] million tons of coal annually—or approximately [redacted] tons per delivery day. Of the total BCC deliveries, it is projected that the BCC surface mining operation will provide the Bridger Plant with approximately [redacted] million tons of coal in 2010, and [redacted] million tons in 2011, and the underground operations will account for approximately [redacted] million tons in 2010, and [redacted] million tons in 2011.

Coal is delivered to the Plant from the BCC mine by use of a large conveyor belt system that transports and delivers coal directly from the mining operation into the Plant. This type of mine-mouth plant operation has several advantages over an operation where

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[3] BCC is one-third owned by Idaho Energy Resources Company ("IERCO"), a subsidiary of Idaho Power, and two-thirds owned by Pacific Minerals Inc.("PMI"), a subsidiary of PacifiCorp. The coal supply agreement between Idaho Power and IERCO was approved by the Oregon Commission by Order No. 91-567 in Docket UI 107 on April 25, 1991.

the coal is delivered from another location. First, the mine mouth operation has the obvious advantage of eliminating the need to ship coal over long distances in order to supply the generating plant—usually at great expense. In addition, the mine mouth operation avoids the undesirable result of locating the coal fired generation plant in close proximity to large population centers which typically correspond to the large load centers.

Q. Where does the Plant get the rest of its fuel?

A. The remainder of the coal consumed by the Plant each year—approximately [redacted] million tons--comes from the Black Butte Mine, which is also located in the Green River Basin, approximately 12 rail miles from the Bridger Plant.

Q. Please describe BCC's underground and surface mining operations.

A. As mentioned above, the Bridger Plant relies on coal from both the surface and underground operations of the BCC mine.

The surface mine commenced commercial operations in August 1974 and has been producing coal for the Bridger Plant since that time. The surface mine utilizes draglines for overburden removal and a truck/shovel fleet for coal removal. The coal is trucked to dump stations and is then transported to the Plant utilizing a conveyor system. Current maximum capacity of the surface mine is approximately [redacted] million tons per year. Because the surface operation is used, in part, to provide operational flexibility to the BCC operation and the Plant itself, the production levels at the surface mine are determined by forecasting BCC underground and Black Butte delivery schedules to ensure that the Plant receives its required coal volumes.

The Company started underground mining operations with the development of the portals and main entries in September 2004 and the first longwall coal production was in March 2007. The primary method of coal extraction at the BCC underground operation is a longwall system. The underground operation is currently operating at capacity and production is limited to its current levels.

Q. Are the surface and underground mines separate operations?

A. No, the surface and underground mines are run as an integrated operation. While the underground mine provides the lion's share of the coal to the Bridger Plant, the surface operation provides coal critical to the blending process, additional capacity, flexibility in running the underground operations, a hedge on prices, and support for the common costs. Both the surface and the underground BCC operations share common assets such as conveyors, scrapers, dozers, light duty vehicles, maintenance shops, administrative buildings, etc. Mine administration personnel including purchasing, planning, engineering, environmental services, information technology, safety, human resources, administration services, government relations and surveying support both operations.

Q. How is the price of BCC coal determined?

A. In 1974, PacifiCorp and Idaho Power entered into a long-term coal sales agreement with BCC. Pursuant to that agreement, and its restatements and amendments, the coal sales price is computed based on BCC's total projected costs and includes a calculated operating margin as provided for in Idaho Power's rate base. The sales price is adjusted periodically as updated cost data becomes available. Each time the sales price is adjusted the parties execute an amendment to the agreement.

Q. Has the Company undertaken any efforts to reduce BCC's mining costs?

A. Yes. BCC pursues best mining practices on a daily basis. BCC has pursued several initiatives that have resulted in reduced costs. BCC is also pursuing a royalty rate reduction with the Bureau of Land Management on federal coal leases. BCC has also employed contractors when cost effective and/or timing dictates. In the spring of 2009, BCC solicited bids for the performance of final reclamation. Reclamation work is being performed per agreement with the Wyoming Department of Environmental Quality. BCC subsequently awarded a bid to Oftedal Construction Inc. Oftedal commenced reclamation activity in

March 2010. With improved predictive maintenance practices, the BCC mine has been able to extend the useful life of surface equipment. By lengthening critical component lives, the mine has been able to lower hourly operating costs. BCC has, where feasible, incorporated into its mine plan the movement of overburden from the surface mine stripping operations and directly placed the overburden in a final mine closure location to reduce rehandle costs.

Q. Mr. Dougherty's adjustment focuses on the costs associated with BCC's surface coal separate from the costs associated with BCC's underground coal, suggesting that Bridger should shut down its surface operations and replace the surface coal with coal purchased from Black Butte or some other third party. Is Mr. Dougherty's recommendation reasonable?

A. No. *First,* as I will explain below, while BCC's surface coal is more expensive than the underground coal, the costs associated with any available replacement coal are higher than the costs that would be avoided if the surface operation ended. In fact, the decremental cost of BCC surface coal is approximately [redacted]. That being the case, the BCC surface coal is the lowest cost resource. *Second*, there is a very significant advantage to the ability of the Company to control the production of the surface mine. For instance, if there were a major issue at the BCC underground operation or at the Black Butte mine that limited coal production, BCC's surface operation could be ramped up to help fill the production void. This diversified approach provides the level of reliable and continuous coal supply that is required by a regulated utility in order to meet its obligation to reliably serve its customers' loads.

Q. You have stated above that the decremental cost of the BCC surface coal is actually $[redacted]. Could you please explain what you mean by the decremental cost and how you made your calculation?

A. As explained above, BCC's underground and surface mines constitute one integrated operation. As such, many of the costs to run the mine are allocated to the coal produced by both the surface and underground mines. If the surface mine were shut down, which is the logical implication of Mr. Dougherty's adjustment, many of the shared costs would not be avoided but rather would need to be reallocated to the cost of the underground coal. In other words, BCC cannot avoid all of the costs allocated to the surface coal by shutting down the surface mine. So, for the purposes of a lower of cost or market analysis, the cost of the surface coal should be considered at the cost that BCC could avoid by shutting down the surface mine—or, the decremental cost of the BCC surface coal.

Q. Has BCC calculated the decremental cost of the surface coal, and if so, please explain how that calculation was made.

A. Yes. BCC calculated the decremental cost of surface coal based upon its most currently available mine plan. The current mine plan projects BCC costs to be [redacted] per ton for the April 2010 through March 2011 test period. These updated production costs were then used as the starting point for the decremental analysis.

To calculate the decremental cost for the test period, BCC projected total mine operating costs based on continued operation of the underground mine and final reclamation activities. Surface coal production was eliminated, which resulted in significant expenditure reductions for labor and benefits, materials and supplies, outside services, and royalties. Surface mine expenditures for severance tax, extraction tax, federal reclamation fees, and black lung excise taxes were eliminated. Unavoidable operating costs previously allocated between surface coal production and final reclamation are charged only to final reclamation which necessitated increased reclamation trust fund contributions. The analysis did not include severance costs that would exist if surface coal production was terminated. In the end the decremental cost of the surface coal at BCC is $[redacted] per ton. In order to ensure a conservative estimate, The Company approximates this cost as $[redacted] for purposes of its analysis in this case.

This analysis estimates that BCC would save approximately $[redacted] for every ton of surface coal not mined. That sum would therefore be available to purchase replacement coal on the open market.

Q. Can you describe how the decremental cost was determined?

A. The decremental analysis prepared for the test period assumed Bridger Coal Company would produce [redacted] million tons of coal at a cost of $[redacted] million or $[redacted] per ton. Without the Bridger surface operation, test period Bridger Coal production would decrease to [redacted] million tons at a total cost of $[redacted] million, or $[redacted] per ton. The estimated decremental mine cost of $[redacted], in this test period, was derived by dividing the dollar differential ($[redacted] million) by the tonnage differential ([redacted] million) between the two plans. The result of the study is a reduction in total BCC cost of $[redacted] and a reduction of [redacted] surface tons for the test period. When you divide the dollars by the tons you get $[redacted] as the decremental cost per ton.

Q. What is the significance of the decremental cost?

A. The decremental cost is the benchmark against which alternative coal costs should be measured because this is the amount it actually costs to purchase coal from BCC's surface mining operation. Later in my testimony I will examine in detail the actual costs of market alternatives available to replace BCC surface coal should the Company be required to do so. This comparison is meaningful only after properly determining the decremental cost of BCC's surface coal.

Q. Does Mr. Dougherty's comparison of BCC surface costs utilize the decremental cost?

A. No. Mr. Dougherty's analysis focuses on the average costs per ton for surface and underground coal reflected in the Company's response to Staff's first data request. Accordingly, Mr. Dougherty assumes that if BCC were to cease its surface mining operation, that BCC's underground coal would continue to be available to the Bridger Plant at the average cost per ton also described in that response. Mr. Dougherty's analysis is flawed, however, because it does not take into consideration the fixed costs associated with the integrated mining operation that cannot be avoided if the surface mine is shut down and that will therefore be allocated to the underground coal. His analysis also fails to account for the increased costs of reclamation the Company would incur if surface mining ends. When all of those costs are considered, it becomes clear it would be more expensive for the Bridger Plant to replace the BCC surface coal with Black Butte coal—or similarly priced alternative coal—than to continue to purchase both underground and surface coal from BCC.

ALTERNATIVES TO BCC SURFACE COAL

Q. You stated above that Mr. Dougherty's analysis is flawed because it erroneously assumes that the Company could replace the BCC surface coal with coal from Black Butte or some other third party. Please explain.

A. The Black Butte mine presently supplies approximately one-third of the coal that is used to fuel the Bridger Plant—approximately [redacted] million tons per year. By defining the "market" as the price paid by the Company for the Black Butte coal, Mr. Dougherty implicitly assumes that the Company could replace the BCC surface mine coal with coal from Black Butte—or some other third party—and at the same price that it is paying for the Black Butte coal that it is currently purchasing. The fact is that it cannot. First, I will describe the terms and conditions under which Black Butte currently supplies coal to the Bridger Plant, and then I will explain why additional Black Butte coal cannot be used to replace the BCC surface coal.

Q. Please describe the Black Butte contract.

A. Effective on October 31, 2008, PacifiCorp, Idaho Power, and Black Butte Coal Company entered into a coal supply contract for coal purchases for the Bridger Plant. This contract has a term of January 1, 2010, through December 31, 2014. Annual volumes range from [redacted] million tons in 2010 to [redacted] million tons for 2011 through 2014. The base price is $[redacted] per ton F.O.B. mine and is adjusted for changes in taxes and royalties, indexed components, and btu content.

Q. Can the Plant purchase additional coal from Black Butte to replace the BCC surface coal?

A. No. First, Black Butte has very little additional coal that it can commit to sell to the Bridger Plant. The vast majority of Black Butte's production is already committed to be sold under the Bridger Plant's current contract, with most of the remainder committed to the North Valmy Power Plant, which is co-owned by Idaho Power and NVEnergy. In fact, in 2008, the Black Butte mine had no excess production capacity at all. [redacted] By way of comparison, BCC projects surface production of approximately [redacted] and [redacted] million tons for 2010 and 2011, respectively. Clearly, Black Butte simply does not have enough volume available to replace the BCC surface production.

Moreover, with respect to the Black Butte coal that *might* be available, there is no evidence that it could be obtained at the same price as under the existing contract. On the contrary, the price quoted by Kiewit Mining for that uncommitted production was substantially higher than the price paid by Bridger under the existing Black Butte contract. Kiewit Mining quoted an F.O.B. mine price of $[redacted] per ton, with an adjustor for changes in diesel fuel costs, for volumes, such as the above referenced [redacted] annual tons, in excess of the new contract. This price does not include the price of shipping the coal from the Black Butte Mine to the Bridger Plant, estimated to be $[redacted] per ton.[4]

Q. How does this cost compare to the cost of BCC's surface-mined coal?

A. As described above, the decremental cost of BCC coal is $[redacted] per ton. This is the amount the Company saves if it does not mine that coal. To replace that coal with Black Butte coal will cost approximately $[redacted] per ton. Thus, the Company would save $[redacted] per ton and pay $[redacted] per ton. This results in an increase in overall coal costs and indicates quite clearly that in fact the BCC surface coal is lower than the price available from Black Butte.

COAL BLENDING PROCESS

Q. Are there any other reasons why BCC's surface coal could not be replaced with Black Butte coal?

A. Yes. BCC's surface coal is an integral part of the necessary blending process before coal is burned at the Bridger Plant. From a coal quality perspective, the Bridger Coal surface and underground operations are complementary. On average, the Bridger surface operation produces the coal with the highest sodium, and lowest ash content and ash softening temperatures, while the Bridger underground operation produces the coal with the lowest sodium, and highest ash content and ash fusion temperatures. Removing the surface coal from the blending process and replacing it with Black Butte coal will adversely impact the efficiency of the plant and also have an adverse environmental impact.

Q. Please describe the blending process that occurs for the Bridger Plant.

A. Because of operational and environmental constraints, the coal that is burned at the Bridger Plant must meet specific quality standards. These standards ensure that the

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[4] Presently, all Black Butte coal is shipped to Jim Bridger by rail. In the past some limited amounts of Black Butte coal have been shipped by truck.

Plant meets all environmental regulations and generates at its optimum level with minimal de-rates. To achieve these standards, coal from different sources is analyzed and blended to conform to the required quality standards.

Q. How does BCC surface-mined coal fit into this process?

A. The surface operation is critical to this coal blending process. All coal, surface and underground, has a certain coal quality. Mine plans are developed on a monthly basis to ensure that the delivered coal product to Bridger meets specific coal quality constraints. These constraints concern ash, slag, and environmental considerations, all of which are sensitive and effected by the chemical make-up of the coal that is burned. On a daily basis mine deliveries are adjusted to meet Plant specifications. All coal blending is performed by the surface mine. Blending is critical because the underground mine operations are limited to a single coal seam. Without the flexibility of the surface operation, BCC could not deliver a coal stream that would meet the requirements of Bridger operations.

All three coal sources for the Bridger plant (BCC surface, BCC underground, and Black Butte) have quality cycles. Geology and quality can vary within a seam as well as from seam to seam. Through blending of coals, both BCC and the Bridger Plant minimize quality variations that undermine optimal Plant performance. Both BCC and the Bridger Plant have installed coal analyzers that provide operations with instantaneous data. With this information, both the Mine and the Plant can adapt their blending.

Q. What other factors affect the coal blending process?

A. Ash content is a very important consideration when blending coal. Because of its importance, BCC has CoalScan Analyzers designed to specifically measure ash content. The ash content of the underground operation fluctuates depending upon the ash content of the mined seam and the amount of coal produced by the continuous miners. In 2010, for instance, the ash content of the underground coal is projected to range from approximately 10 percent to 22 percent. Comparatively, the ash content of the surface operation is projected to be from 7 percent to 13 percent. The coal burned in the generating units should have an ash content of 12 percent or less; thus, blending the surface and underground coal is necessary to achieve usable coal.

In addition to ash content, the Plant also has established coal quality targets for heat content (Btu/lb), ash softening temperature, iron, sodium, and calcium. Sodium, ash, and heat content are the most critical variables. As previously stated, from a coal quality perspective, the BCC surface and underground operations are complementary. On average, the BCC surface operation produces the coal with the highest sodium, and lowest ash content and ash softening temperatures, while the BCC underground operation produces the coal with the lowest sodium, and highest ash content and ash fusion temperatures. Fueling plans are prepared to ensure BCC coal deliveries, in aggregate, conform to established targets.

The Bridger Plant also performs limited blending. To maximize generating availability, a Thermo Fischer CQM Elemental Analyzer has been installed at the Plant. This analyzer provides the Plant with instantaneous coal quality data as coal is transferred from the stockpile to the coal silos. The Plant operator is provided with measurements of moisture, ash, sulfur, btu content, ash softening temperature, iron, calcium, and sodium.

Q. Has BCC applied these coal quality targets to all coal supplied to the Bridger Plant?

A. Yes. Coal quality targets have been established for heat content (btu/lb), ash content, sulfur, ash softening temperature, sodium, calcium and iron for BCC, Black Butte coal, and the Bridger Plant. Personnel from the PacifiCorp Fuels Department, BCC, Idaho Power, and the Bridger Plant all participate in daily calls to discuss and review the fueling plans. BCC adjusts its coal quality to meet the Plant's requirements. Depending upon

Black Butte's coal quality, BCC will adjust the proportion of surface and underground deliveries to ensure coal, in aggregate, conforms to established targets at the Plant.

The following table illustrates the coal quality targets that have been developed:

Coal Quality Targets

	Bridger Coal Company	Black Butte Coal	Jim Bridger Plant
Btu Content	> 9200	> 9000	> 9200
Ash	12% - 14%	11.50%	12%
Sulfur	0.60%	0.60%	0.60%
Ash softening Tempeature	> 2175		> 2175
Sodium	2% - 3%	< 4%	< 3.2%
Calcium	< 8%		< 8%
Iron	< 6%		< 6%

As this table illustrates, the Plant relies on blending from all three sources of coal to achieve the most efficient coal for combustion at the Plant.

Moreover, even in months when there is no surface production, BCC can ensure a consistent coal quality by blending stockpiled coal.

Q. How does Black Butte coal fit into the overall blending process for the Bridger plant?

A. Similar to BCC coal, Black Butte ships a blended coal product. Black Butte is currently mining in two pits. The two active pits, Pit 14 and Pit 11, have significantly different sodium levels and heat content. The sodium content of Pit 11 is much higher and can cause slagging of ash on the boiler walls. This can cause a de-rating of the Plant during slag removal operations.

The Bridger Plant has established an approximate 3 percent sodium target. At times, the Black Butte mine has had limited production capacity of low sodium content coal. During periods when high sodium Black Butte coal is delivered, low sodium BCC surface coal is critical for blending. Black Butte coal is blended with BCC coal at the Bridger Plant. Under the prior Black Butte coal supply agreement, in addition to their deliveries by rail, Black Butte sourced the Bridger Plant with [redacted] tons of premium low sodium, high ash fusion temperature coal from Pits 22, 23 and 24 (Leucite Hills Mine). This coal was transported by truck and stockpiled by Black Butte at a site adjacent to the Bridger Plant. Bridger Plant personnel utilized this coal for blending on an as needed basis. These ultra-low sodium reserves, however, were depleted in 2009.

Under the new Black Butte agreement, with the term of 2010 though 2014, the coal is being sourced from the higher sodium Pit 11 and Pit 14. The current contract specification allows Black Butte to ship coal with up to 4 percent sodium on a monthly basis. Sodium content above 3.2 percent causes ash to slag on the boiler tubes. As a result blending with lower sodium BCC coal is required to mitigate Black Butte coal deliveries with sodium content above 3 percent.

Q. Have there been issues with the quality of Black Butte coal in the past?

A. Yes. In 2008, mining at Black Butte was limited to two pits: Pit 8, a low sodium coal, and Pit 11, a high sodium coal. Low sodium coal production was limited as Pit 8 reserves were close to depletion. Due to limited Pit 8 supplies, Black Butte's deliveries to the Bridger Plant averaged in excess of 4.5 percent sodium in 2008 which necessitated blending of low sodium coal from the BCC surface mine. The Bridger Plant owners had several meetings with Black Butte in 2008 regarding the sodium content and limited supply. Sodium content remained high and excess supply non-existent until Black Butte subsequently opened Pit 14, in 2009. Utilizing exclusively Black Butte coal, without BCC surface mine deliveries in 2008, the Bridger Plant would have sustained persistent MW de-ratings due to slagging from Black Butte coal.

Q. How does this blending process affect the application of the lower of cost or market rule?

A. Mr. Dougherty proposes replacing the BCC surface operations with Black Butte coal. As demonstrated above, however, BCC surface coal (and the combined BCC coal product) are necessary to the blending process and ensure that the process is performed in the most cost-effective manner and performed to maximize the efficiency of the Plant's operations. Thus, even if sufficient volumes were available from Black Butte, replacement of BCC surface coal with Black Butte coal poses serious blending problems for the Plant.

Mr. Dougherty's Second Alternative Analysis, which replaces the surface coal with underground coal, also ignores this blending process which requires both surface and underground coal to create a usable final product for the Plant.

Q. You have explained why Black Butte coal cannot replace BCC surface coal. However, aren't there other alternative sources in the Green River Basin from which the Company can purchase coal to replace BCC's surface operations at a savings to customers.

A. No. Aside from BCC and Black Butte, there is only one additional operating coal mine in the Green River Basin—the Kemmerer Mine. The Kemmerer Mine is dedicated to supplying PacifiCorp's Naughton power plant, with the remainder going to supply industrial customers in the region. There is no additional coal available from this source.

Q. If the Company cannot obtain replacement coal from the GRB, what is the next logical alternative?

A. The only other viable source of coal to fuel the Plant are mines located in the Powder River Basin ("PRB")—which is located approximately 566 miles from the Plant. There are, however, two significant problems with using PRB coal. The first is the effort and expense involved in shipping coal from the PRB to the Bridger Plant. The estimated cost to ship coal from the PRB to the Bridger Plant is around $[redacted] per ton, which is double the estimated $[redacted] per ton cost the coal itself. In total, the per ton cost of PRB coal, including transportation is likely to be at least $[redacted] per ton F.O.B. Plant without adding in additional costs such as freeze protection and dust suppression. Assuming that significant volumes of PRB coal could be obtained and then shipped to the Plant, use of coal from mines in the

PRB would require significant capital investment in the Plant because of the different quality and chemical make-up of the coal compared to the GRB coal the plant currently burns. These issues with the Powder River Basin make it uneconomical to consider coal from that region as a possible fuel source for the Plant.

Q. Is there a spot market from which the Plant could acquire coal to replace the BCC surface coal?

A. No. Because of the location of the Bridger Plant there is no spot market that can serve it. Moreover, because the Plant is a baseload resource requiring a consistent and reliable source of coal, prudent operation dictates that it contract for its coal to ensure a stable supply.

STAFF'S RECOMMENDATIONS

Q. Based on the foregoing analysis, how does the Company respond to Mr. Dougherty's specific recommendations?

A. Mr. Dougherty's testimony includes a Primary and First Alternative Analyses which he recommends and a Second and Third Alternative Analysis that he does not recommend. Mr. Dougherty's Primary and First Alternative Analyses call for the replacement of the BCC surface coal with Black Butte coal. As explained above, there are significant problems with both these analyses. *First*, Black Butte is not an alternative market available to supply coal in lieu of the surface operations. At most Black Butte coal could replace approximately one-third of the BCC surface coal. *Second*, the decremental cost of surface coal is actually *less* than the replacement cost of Black Butte coal. *Third*, the current BCC coal costs are actually lower than the cost of replacement coal from Black Butte. *Fourth*, obtaining coal to replace the remaining two-thirds of BCC surface coal from the PRB will greatly increase coal costs because that coal, including transportation, is significantly more expensive than BCC coal. *Fifth*, reduced availability of BCC surface coal would make blending to meet coal quality requirements impossible at times and cause de-rating of the

Plant, thus increasing the cost of generation. Thus, when the LCM rule is properly applied to BCC coal costs it is evident that in fact the BCC costs, including the surface operation, are lower than the cost to replace that coal through market purchases from non-affiliated mines.

Mr. Dougherty's Second Alternative Analysis, which he does not recommend, replaces the surface coal with BCC's underground coal. This analysis is also flawed for several reasons. *First*, BCC's underground coal is not available to replace the surface coal because it lacks the necessary capacity and the surface coal is an essential component of the blending process required to safely and efficiently operate the Bridger Plant. *Second*, the LCM rule applies to goods transferred within a market, not to individual cost components included in an affiliate's overall costs. *Third*, if surface operations ceased, the cost of underground operations would increase because of the shared overhead expenses. Thus, if surface mining ended, the costs of the underground operation would not be the amount reflected in this filing because that amount assumes surface operations exist.

Mr. Dougherty's Third Alternative Analysis, which he does not even recommend is also flawed. This proposal replaces all BCC coal with Black Butte coal, including carry-over tonnage. As demonstrated above, replacing BCC's [redacted] million tons of coal with Black Butte's [redacted] tons of additional capacity is unrealistic. Thus, Black Butte coal is not an available market for replacement coal. Moreover, removing the BCC surface coal from the essential blending process would result in significant problems for the Bridger Plant.

The following table illustrates the cost comparison between BCC's surface coal costs and alternative sources of coal proposed by Mr. Dougherty:

Coal Source	Cost Per Ton (including transportation)
BCC Surface Decremental (Apr. 2010 through Mar. 2011)	$[redacted]
Black Butte (Staff's Primary Analysis)	$[redacted]
Black Butte (Staff's First Alternative Analysis)	$[redacted]
Black Butte Replacement (400,000 tons)	$[redacted]
PRB Coal	$[redacted]

As is clear from this comparison, BCC surface coal is lower in cost than any available coal from either Black Butte or the PRB.

Q. What is the difference between the Primary and First Alternative Analyses?

A. The only difference between the two analyses is that the Primary method includes carry over tonnage from the previous Black Butte contract. Inclusion of the price for carry over tons is inappropriate because Mr. Dougherty is attempting to define a market rate—the cost at which the Company could go into the marketplace and actually purchase coal in lieu of purchasing coal from its affiliate. Carry-over tonnage—coal provided at a lower cost because it should have been delivered in a previous year with a lower cost—does not factor into a proper market analysis. If the Company were negotiating to purchase coal to replace the BCC surface coal it could not expect that other suppliers would give it the same price that Black Butte gave it in past years. Benefits from this carry-over tonnage are already included in the case and therefore customers will receive the benefit of the carry-over tonnage even without his adjustment.

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

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-01

IDAHO POWER COMPANY

ATTACHMENT NO. 4

AURORA Output 1982 Hydro Condition