Docket No. 12-035-92

OCS Exhibit 1.4

RMP Responses to Data Requests Referenced in the Testimony of Randall J. Falkenberg for the Office of Consumer Services

OCS Data Request 12.1

Please refer to file PVRR_Tables_Final_JB3+4.xlsx, tab Mine Capital Adjustment, cells D75, which represents the "As Modeled" coal mining capital cost for all four Bridger units in the continued coal operation case. Review of other documents, Attachment OCS 1.64 1st Supplemental Attachment and Attachment OCS 1.64 does not appear to demonstrate the Bridger 3 and 4 coal mining capital costs were included in the gas operation revenue requirement. Instead only half (the portion associated with Units 1 and 2) were included as part of the fixed costs of Units 1 and 2 in the SO Model. If so, then it would appear the coal mining capital adjustment in cell D77 may be incorrect. Please indicate whether the Company agrees or not, and if not, explain where the total plant revenue requirement for Bridger coal (the amount shown in Cell D75) has been included. If the Company agrees that the costs are misstated please provide a correction to the figure in Cells D75, D76, D77 and other cells as needed.

Response to OCS Data Request 12.1

The data in the file PVRR_Tables_Final_JB3+4.xlsx, tab Mine Capital Adjustment, cell D75 contains the "As Modeled" mine capital costs for the Jim Bridger plant. These data are consistent with the inputs to the System Optimizer model (SO Model), which split the Jim Bridger plant costs among the four Jim Bridger units. The data provided with the Company's response to OCS Data Request 1.64; specifically Confidential Attachment OCS 1.64, contains a proportionate share of the "As Modeled" mine capital costs for Jim Bridger Units 3 and 4. The proportionate share of mine capital costs are also included in the SO Model for Jim Bridger Units 1 and 2, but were not provided in the Company's response to OCS Data Request 1.64. Note: OCS Data Request 1.64 only requested data for Jim Bridger Units 3 and 4.

The data in the file PVRR_Tables_Final_JB3+4.xlsx, tab Mine Capital Adjustments, cell D76 contain updated mine capital costs for the Jim Bridger plant in the case of gas conversion of both Jim Bridger Units 3 and 4. The adjustment in cell D77 calculates the change in mine capital costs in the case of gas conversion, and applies this change as an adjustment to the PVRR results shown in the gas conversion case within the tab Exhibit 3 – PVRR Tables. This application of the adjustment in cell D77 assumes that the "As Modeled" mine capital costs as input to the SO Model are equal to the "As Modeled" mine capital costs reported as an output from the SO Model. However, when the SO Model selects a gas conversion alternative for a given unit, it does not report the proportionate share of mine capital beginning in the year conversion occurs, and therefore, the assumption that mine capital input to the SO Model equals the mine capital output from the SO Model is not valid. As such, the adjustment in cell D77 is incorrect. Please refer to Confidential Attachment OCS 12.1 with corrected figures, applied by adding rows 76 and 79, with the revised adjustment shown in cell D79.

The effect of this revised adjustment is to increase the cost in the case of gas conversion at Jim Bridger Units 3 and 4, which improves the economics in favor of the selective catalytic reduction (SCR) investment by approximately $105 million among all scenarios applied to the combined Jim Bridger Unit 3 and Unit 4 analysis. The revised adjustment was further applied to the PVRR(d) results shown in the tab Exhibit 3 – PVRR Tables in those cells highlighted red.

Confidential information is provided subject to Utah PSC Rule 746-100-16.

12-035-92/Rocky Mountain Power
November 2, 2012
OCS Data Request 12.3

OCS Data Request 12.3

Please refer to Attachment WIEC 10.6 from the current Wyoming Bridger CPCN (Docket No. 20000-418-EA-12), cell G55, which represents fixed costs of Bridger Unit 4 included in the SO Model Gas Conversion case in 2016. This figure matches the value in Attachment OCS 1.64, Cell H30 of the Jim Bridger 4 tab. Please identify any costs included in the figure in Cell H30 which the Company agrees should not be included in the Bridger gas conversion cases.

Response to OCS Data Request 12.3

OCS references the Company's response to WIEC Data Request 10.6 in the Company's Wyoming proceeding (Docket No. 20000-418-EA-12) in this request. Note: the same request/response is OCS Data Request 8.6 in this proceeding.

Referring to the Company's response to OCS Data Request 1.64; specifically Confidential Attachment OCS 1.64 – the costs in cell H30 that should be removed from the gas conversion case include the 2016 real levelized capital costs associated with the selective catalytic reduction (SCR) and the 2016 O&M costs associated with the SCR. These costs total $21.3 million in 2016 or $16.2 million on a PVRR basis (2012$).

Please refer to Confidential Attachment OCS 12.3, which combines adjustments made in Confidential Attachment OCS 12.1 with the revisions noted above.

Confidential information is provided subject to Utah PSC Rule 746-100-16.

OCS Data Request 12.2

Please refer to Attachment WIEC 10.6 from the current Wyoming Bridger CPCN (Docket No. 20000-418-EA-12), cell G55, which represents fixed costs of Bridger Unit 4 included in the SO Model Gas Conversion case in 2016. This figure matches the value in Attachment OCS 1.64, Cell H30 of the Jim Bridger 4 tab. Does the Company agree that the figure in Cell H30 contains revenue requirements associated with the Bridger SCR for 2016, which was later reversed out of the Bridger coal operation case (See PVRR_Tables_Final_JB3+4.xlsx, tab Env Capex Adj.) but not out of the gas-fired operation case? If not, please indicate where the reversal of this amount was completed, or explain why it should not be reversed as there would be no need for SCR in the gas conversion case.

Response to OCS Data Request 12.2

OCS references the Company's response to WIEC Data Request 10.6 in the Company's Wyoming proceeding (Docket No. 20000-418-EA-12) in this request. Note: the same request/response is OCS Data Request 8.6 in this proceeding.

Referring to the Company's response to OCS Data Request 1.64; specifically Confidential Attachment OCS 1.64 - the costs in cell H30 of the Jim Bridger 4 tab contain costs associated with the Jim Bridger Unit 4 selective catalytic reduction (SCR) in 2016 that were adjusted, not "reversed", in the file "PVRR_Tables_Final_JB3+4.xlsx", tab Env CapEx Adjustments, for the coal operation case. Similar adjustments were not applied to the gas conversion case, nor were costs reversed out of the gas conversion case.

12-035-92/Rocky Mountain Power
November 26, 2012
DPU Data Request 9.1

DPU Data Request 9.1

Would the Company agree that the maximum capacity for the Wyodak coal unit is incorrectly set to 330 megawatts in the Company's System Optimizer runs? If not, please explain.

Response to DPU Data Request 9.1

The Company agrees that the Wyodak coal unit was incorrectly set to 330 megawatts. However, given the incorrect capacity was inadvertently applied in both the Optimized and Change Case System Optimizer model (SO Model) simulations, it would not significantly alter the PVRR(d) for the Jim Bridger Units 3 and 4 selective catalytic reduction (SCR) investments.

12-035-92/Rocky Mountain Power
September 26, 2012
OCS Data Request 4.8

OCS Data Request 4.8

Link Testimony, p. 16, lines 311-321; Confidential Exhibit RTL-4.

a. Please describe the Wyoming DEQ requirements and rules that require final reclamation of the Bridger surface mine by 2021 in the two and three unit operation scenarios. Please provide the assumed closure date(s).
b. Please explain why PacifiCorp assumes that reclamation costs must be recovered prior to the completion of reclamation.
c. In the two or three unit operation scenario, what assumption does PacifiCorp make with respect to the recovery of any net rate base for the generation units that are closed or retired in 2015?

Response to OCS Data Request 4.8

a. In both the two-unit and three-unit operation, the draglines cease uncovering coal in 2013 and are diverted to final reclamation. Coal is recovered from the former surface mine areas by highwall mining extraction through 2017 and the underground mine produces coal through 2037. Highwall mining (which negates further surface mine development) further establishes that surface mining development is no longer economic and that "the earliest possible reclamation program" for areas not part of the underground mine can be initiated.

   Reclamation Requirements
   The Wyoming Statutes and the Environmental Protection Performance Standards promulgated by the Wyoming Department of Environmental Quality, Land Quality Division establish requirements for final reclamation for coal mining operations. Wyoming Statutes Title 35 – Public Health and Safety, Chapter 11 – Environmental Quality, Article 4 – Land Quality, 35 -11-402 Establishment of Standards (a) (iii) establishes reclamation regulations requiring "a time schedule encouraging the earliest possible reclamation program consistent with orderly and economic development of the mining property;"

   The performance standards established by the Wyoming Department of Environmental Quality, Land Quality Division Chapter 4 – Environmental Protection Performance Standards for Coal Mining Operations include:

   Section 2 – General Environmental Protection Performance Standards,
   (b) Backfilling, grading and contouring.
   (i) Rough backfilling and grading shall follow coal removal as contemporaneously as possible based upon the mining conditions. The operator shall include within the application for a permit to mine a proposed schedule for backfilling and grading with supporting analysis.

(k) Time schedule:

(i) Reclamation must begin as soon as possible after mining commences and must continue concurrently until such time that the mining operation is terminated and all of the affected land is reclaimed. If conditions are such that final reclamation procedures cannot begin until the mining operation is completed, this must be explained in the reclamation plan. A detailed time schedule for the mining and reclamation progression must be included in the reclamation plan. This time schedule shall:

(A) Apply to reclamation of all lands to be affected in the permit area;
(B) Designate times for backfilling, grading, contouring and reseeding;
(C) Be coordinated with a map indicating the areas of progressive mining and reclamation;
(D) Establish reclamation concurrently with mining operations, whenever possible. If not possible, the schedule shall provide for the earliest possible reclamation consistent with the orderly and economic development of the property; and
(E) If the Administrator approves a schedule where reclamation follows the completion of mining, describe the conditions which will constitute completion or termination of mineral production.

Mine Permit

All mining operations are required to have an approved Permit to Mine which is administered by the Wyoming Department of Environmental Quality, Land Quality Division. The mine permit requires the mining operation to submit a reclamation plan as described in the Wyoming Statutes Title 35 – Public Health and Safety, Chapter 11 – Environmental Quality, Article 4 – Land Quality, 35 -11-406 Application for permit; generally; denial; limitations (b) (i). This section states that "The application shall include a mining plan and reclamation plan dealing with the extent to which the mining operation will disturb or change the lands to be affected, the proposed future use or uses and the plan whereby the operator will reclaim the affected lands to the proposed future use or uses…". Bridger Coal operates under the approved Permit to Mine #338-T6. The five-year permit term is 2007 through 2012.

The mine and reclamation plan in the current permit supports the economic life of the operation as known at the time of term submittal. The permit includes a reclamation plan that specifies reclamation grading yardage in periodic increments. The permitted mine and reclamation plan shows that surface mining concludes in 2024 and that reclamation is completed in 2028, within five years. Reclamation is expected to occur at an expedient rate once surface mine coal production ceases. Failure to proceed with final reclamation in expedient manner is subject to fines and administrative orders.

Reclamation Requirements in two and three unit surface closure scenarios
Final reclamation grading in the proposed plan starts in 2012 as coal production begins to transition from the surface mining equipment to highwall mining recovery. This plan is based on a levelized equipment schedule for continuous, non-overtime grading and topsoil placement that emulates the time-frame for final reclamation that exists in the approved mine permit. Final reclamation is conducted during the two phases: (i) post the surface and highwall mining (2012- 2021) and (ii) post underground mining.

(i) Post Surface Mine Reclamation: In this phase, reclamation is done in surface mine disturbed areas that are not in the vicinity of the still operating underground mine. Both draglines are scheduled to perform reclamation grading along with production excavation in 2012 and 2013. In 2014 and 2015 the draglines support the highwall mining operation and conduct reclamation grading, with the percentage of grading time increasing during the period. From 2016 to 2020 the draglines are scheduled full-time in reclamation grading.

The mobile equipment fleets (loaders-trucks, dozers, scrapers) begin part time reclamation work in 2012, transition to full-time in 2013 and finish in 2021. Two truck-loader fleets are used for coal production, and reclamation grading and topsoil replacement. Three Caterpillar D11 class dozers and three Caterpillar 657 class scrapers are scheduled for reclamation grading.

(ii) Post Underground Mine Reclamation: In this phase, reclamation is done in disturbed areas that are available after the underground mine ceases production in 2037. Final reclamation grading and topsoil replacement begins in 2038 and concludes in 2043.

b. Per Bridger Coal Company's mine permit and existing laws, Bridger Coal Company is required to perform final mine reclamation. In January 1989, Bridger Coal Company, Pacific Minerals Inc, Idaho Energy Resources, PacifiCorp and Idaho Power Company executed the Reclamation Fund Agreement establishing a dedicated final reclamation trust fund to meet the costs of final mine reclamation. Per the coal supply agreement between PacifiCorp, Idaho Power and Bridger Coal Company, contributions to the trust are included as a cost of mining coal. Reclamation expense has historically been recognized on an accrual basis for accounting and recovered on an accrual basis for ratemaking in the jurisdictions in which PacifiCorp serves. To do otherwise would potentially expose the Company and customers to a disproportionately large portion of a mine's reclamation costs at the time reclamation begins and similarly expose the Company and its customers to counterparty non-performance under the coal sales agreement.

c. If any of the Jim Bridger generating units were to retire earlier, the remaining rate base would continue to be recovered from customers following appropriate regulatory requirements and processes. In the current proceeding, the next best alternative to the installation of emission control equipment is to convert Jim Bridger generating units 3 and 4 to gas-fired facilities, rather than retire the two units.

12-035-92/Rocky Mountain Power
October 11, 2012
OCS Data Request 6.25

OCS Data Request 6.25

Please explain whether the Bridger coal mine would be a viable operation for selling coal into the open market in the event that Bridger 3 and 4 cease operations? Please respond to the same question for all four Bridger units. Please explain the answer.

Response to OCS Data Request 6.25

No. Bridger Coal Company is located in southwest Wyoming, a relatively small niche market. The vast majority of the coal produced in this region is consumed locally either by the "trona" patch companies or power plants. Currently, an imbalance exists between supply and demand for Southwest Wyoming coal. Kiewit Mining initially commenced operation of the Haystack mine in 2011; however, the Company understands that Kiewit Mining has now delayed development of the mine due to lack of demand. The planned conversion of Naughton Unit 3 from coal to natural gas will further exacerbate the current market disequilibrium. Finally, the lack of competitive transportation alternatives undermines the ability of Southwest Wyoming coals to economically compete with coals from other production basins.

12-035-92/Rocky Mountain Power
September 24, 2012
OCS Data Request 1.61

OCS Data Request 1.61

Does the Company agree that the EFOR data used in its GRID and SO Models supplied in this case for Bridger 3 and 4 are lower than the levels assumed **in any General Rate Case in Utah since 2001**? If not, please provide all data supporting the Company's position. Alternatively, please provide the EFOR's **used in GRID in all Wyoming GRC's for Bridger 3 and 4 since 2001**.

Response to OCS Data Request 1.61

The Company assumes that the reference above to Wyoming was intended to reference Utah. Based on that premise, the Company responds as follows:

Yes.

12-035-92/Rocky Mountain Power
September 24, 2012
OCS Data Request 1.60

OCS Data Request 1.60

Please provide data showing the annual average EAF, CF, SOF, EFOR, and FOR for Bridger Unit 3 and 4 for each year of the unit's operating life.

Response to OCS Data Request 1.60

The Company objects to this request as overly broad and burdensome and not likely to provide evidence pertinent to this docket. Notwithstanding this objection, the Company hereby provides the following information.

	Jim Bridger No. 3 Unit					Jim Bridger No. 4 Unit				
Yr.	EAF	CF	SOF	EFOR	FOR	EAF	CF	SOF	EFOR	FOR
1992	87.60	86.72	8.24	4.53	2.89	91.26	89.45	0.00	8.74	4.60
1993	92.75	87.10	0.00	7.30	4.96	75.89	71.82	10.04	15.75	13.82
1994	85.14	84.73	7.29	8.16	5.14	92.15	91.26	0.00	7.85	5.31
1995	94.26	86.46	1.09	4.77	4.03	87.97	79.44	7.69	4.60	3.28
1996	80.11	71.35	7.91	13.01	7.65	91.56	79.19	0.00	8.44	3.03
1997	88.59	80.05	0.44	11.02	8.97	83.90	73.29	8.97	7.83	2.91
1998	92.86	90.19	1.72	5.51	2.66	88.79	82.26	0.00	11.21	5.75
1999	82.43	79.93	8.13	10.26	4.13	83.63	80.92	1.84	14.78	9.08
2000	93.39	90.37	1.03	5.60	1.16	81.24	78.54	11.12	8.58	5.62
2001	92.38	88.14	1.98	5.58	1.75	91.10	86.17	0.99	7.89	5.35
2002	89.28	84.72	0.92	9.81	4.15	80.81	76.37	7.81	12.27	4.32
2003	69.24	66.76	14.36	19.03	8.39	82.35	79.14	0.94	16.79	7.83
2004	81.10	78.50	1.06	17.86	11.11	74.54	72.68	12.61	14.58	5.87
2005	86.34	84.09	2.68	11.20	4.10	83.17	80.83	0.95	16.01	5.90
2006	88.39	83.39	1.70	9.96	4.25	85.69	81.34	2.97	11.57	4.65
2007	73.07	71.32	18.26	10.43	5.79	86.25	83.61	0.23	13.47	8.56
2008	93.60	89.17	1.56	4.86	2.30	73.49	71.06	22.48	5.04	1.70
2009	93.55	86.51	2.39	4.09	2.38	93.14	86.16	1.41	5.46	2.84
2010	90.93	84.27	0.27	8.77	6.94	91.28	83.13	4.31	4.68	3.34
2011	72.70	58.63	17.28	12.08	8.68	92.09	73.65	1.39	6.59	5.32

OCS Data Request 1.55

Please refer to the "Master Assumption.xls" document provided by the Company. Provide all documents used to create the data in Tab 13 and 13a. - Coal Availability and Monthly Coal Availability.

Response to OCS Data Request 1.55

Coal availability and monthly coal availability for 2012 – 2021 were produced for the ten year plan. The years 2022 – 2030 are an extrapolation of the first ten years provided by the respective plant management staff.

12-035-92/Rocky Mountain Power
September 24, 2012
OCS Data Request 1.83

OCS Data Request 1.83

Would early retirement of Bridger Units 3 and 4 enable the deferral or avoidance of any of the Gateway transmission links? If so, please identify which links and over what period of time. If not, please explain all reasons why not.

Response to OCS Data Request 1.83

Retirement of Jim Bridger 3 and 4 would reduce the need to transport thermal resources westward between the proposed Anticline substation and existing Populus substations from Wyoming to the Company's load centers but, it would not avoid the need for more transmission capacity out of Wyoming. The Company's existing transmission system in Wyoming is highly constrained east of Bridger and limits the Company's ability to reliably transport low cost energy including existing and future thermal and renewable energy sources therein. Retirement of Bridger Units 3 and 4 would not avoid the need for Gateway West in that regard.

OCS Data Request 1.84

Would the answer to the preceding question be the same if it were assumed that the retired Bridger Units were replaced by combined cycle plants located closer to load centers? Please explain.

Response to OCS Data Request 1.84

Yes. Reduced need to transport thermal generation from Bridger to load centers served by Gateway but would not avoid the need for additional transmission capacity from Wyoming.

12-035-92/Rocky Mountain Power
September 24, 2012
OCS Data Request 1.19

OCS Data Request 1.19

Regarding the wind and solar projects included in the GRID and SO Model studies, please indicate whether those were selected on the basis of economics (i.e. being part of the least cost expansion plan) or on some other basis, such as being required to meet an RPS in Oregon, Washington or California.

Response to OCS Data Request 1.19

The wind and solar projects included in the GRID and System Optimizer model (SO Model) studies are consistent with the wind and solar projects in the Company's 2011 Integrated Resource Plan Update (2011 IRP Update), which is provided as Confidential Exhibit RMP___(CAT-7) which accompanies the Direct Testimony of Company Witness, Chad A. Teply.

Wind resources include those required to meet both state and assumed federal renewable portfolio standards (RPS) requirements and incremental wind resources recognizing long-term regulatory compliance/incentive uncertainty, long-run public policy goals, and risk mitigation benefits of zero carbon, zero fuel cost renewable resources. Please refer to Chapter 5 of the 2011 IRP Update.

Solar resources are included to meet compliance with Oregon's solar capacity standard and consistent with Oregon's solar incentive pilot program.

The SO Model was configured to select incremental renewable resources above those levels of wind and solar in the 2011 IRP Update; however, no incremental renewables were selected in any of the scenarios.

12-035-92/Rocky Mountain Power
October 10, 2012
OCS Data Request 6.1

OCS Data Request 6.1

Please refer to the response to WIEC 1.19, and CT-7, Table 5.2. It appears from these documents that the Company has included additional wind generation in GRID and the SO model required to meet the assumed Federal RPS. If so, please provide an analysis showing the amount of incremental wind (and any other renewable generation) required to meet the assumed Federal RPS, that is in excess of the currently existing state RPS requirements. If there is none, please explain.

Response to OCS Data Request 6.1

OCS's reference to "WIEC 1.19" is to the Wyoming CPCN application for Jim Bridger Units 3 and 4 (Wyoming Docket No. 20000-418-EA-12). In this proceeding, "WIEC 1.19" is "OCS 1.19".

There is no incremental wind added to the GRID model and System Optimizer model (SO Model) used to meet the assumed Federal renewable portfolio standards (RPS) requirement. Wind resource additions satisfy state RPS requirements in Oregon, Washington, and California. In meeting these state RPS requirements, the assumed Federal RPS requirements in Table 5.2 are more than satisfied.

12-035-92/Rocky Mountain Power
November 1, 2012
OCS Data Request 13.3

OCS Data Request 13.3

In reference to CAT7, page 46 and OCS 6.1 1st Supplemental, the Company indicates that the cost of renewable resources added to meet western state RPS requirements is assumed to be allocated on a situs basis and that all of the wind resources being brought on line by 2025 are assumed to be required for the Oregon, Washington and California RPS. If so, should the generation be removed from the GRID and SO Models in order to provide a view of the economics of the SCR project from the perspective of PACE customers as they will apparently share in neither the nor generation of these resources? If not, explain why not.

Response to OCS Data Request 13.3

Wind resource additions to meet western state RPS requirements are not scheduled to be placed in service until the 2018 timeframe. There is currently no regulatory cost allocation methodology beyond 2016, so it is not certain how situs assigned resources will be treated in regulatory filings. Nonetheless, the Company notes that the referenced renewable resources and the associated costs are not incremental between the alternatives (operate as coal vs. gas conversion). That is, the same amount of energy and costs would be used in the continued coal-fueled alternative simulation and the converted gas-fueled alternative simulation, regardless of the methodology assumed for cost allocation of situs assigned resources, when establishing the PVRR(d) for the selective catalytic reduction (SCR) investments required at Jim Bridger Units 3 and 4.

12-035-92/Rocky Mountain Power
November 1, 2012
OCS Data Request 12.7

OCS Data Request 12.7

Has the Company included the assumed Federal RPS in its development of the market price forecasts it used in this proceeding, and in the June 30, 2012 OFPC? If so, please explain how the assumed Federal RPS impacts the market price forecast.

Response to OCS Data Request 12.7

The Federal renewable portfolio standards (RPS) are included in the market price forecasts. The Company has not performed an analysis that quantifies the impact on the market price forecast.