Exhibit No. BGM-1CT
Docket UE-152253
Witness: Bradley G. Mullins

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
v.	)	DOCKET UE-152253
PACIFIC POWER & LIGHT COMPANY,	)	
Respondent.	)	

CONFIDENTIAL RESPONSE
TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

BOISE WHITE PAPER, L.L.C.

CONFIDENTIAL PER PROTECTIVE ORDER IN
WUTC DOCKET UE-152253

(REDACTED VERSION)

March 17, 2016

TABLE OF CONTENTS TO THE
CONFIDENTIAL RESPONSE TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT INDEX

Exhibit No. BGM-1CT:	Confidential Response Testimony of Bradley G. Mullins
Exhibit No. BGM-2:	Qualification Statement of Bradley G. Mullins
Exhibit No. BGM-3:	First Rate Period Revenue Requirement Calculations
Exhibit No. BGM-4:	Second Rate Period Revenue Requirement Calculations
Exhibit No. BGM-5C:	The Company's Responses to Discovery Requests (Confidential)
Exhibit No. BGM-6	Rate Base Adjustment for Jim Bridger and Colstrip
Exhibit No. BGM-7	Excerpts from West Control Area Inter-Jurisdictional Allocation Methodology ("WCA") Manual
Exhibit No. BGM-8	First Rate Period Rate Design for Schedule 48
Exhibit No. BGM-9	Second Rate Period Rate Design for Schedule 48

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins. My business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent energy and utilities consultant representing large energy consumers located throughout the West. I am appearing on behalf of Boise White Paper, L.L.C. ("Boise"), which is served by Pacific Power & Light Company ("Pacific Power," "PacifiCorp," or the "Company"). Boise is the Company's largest customer in Washington, purchasing both power and power delivery at its paper mill in Wallula, Washington.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my educational background and working experience can be found in Exhibit No. BGM-2.

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. My testimony addresses policy, revenue requirement, and Schedule 48 rate design. It is in response to the Company's November 25, 2015 Petition for a Rate Increase Based on a Modified Commission Basis Report, Two-Year Rate Plan, and Decoupling Mechanism. In that filing, the Company has proposed to implement two successive 2.99% rate increases over a two-year period, with a cumulative impact of 6.06%. This would represent a substantial rate increase to customers, and as I will discuss below, is largely dependent upon complicated policy decisions regarding coal and attrition.

Q. PLEASE SUMMARIZE YOUR KEY CONCLUSIONS AND RECOMMENDATIONS.

A. A summary of my key conclusions and recommendations is as follows. My testimony has a section for each issue, in respective order:

1. ***Policy: Accelerated Coal Depreciation.*** *If the Washington Utilities and Transportation Commission ("WUTC" or the "Commission") is going to accept accelerated depreciation, it should also exclude from rates costs meant to extend the economic life of coal facilities.*

2. ***Policy: The Rate Plan and Attrition.*** *The Company has not prepared an attrition study, and therefore, has not justified its second rate increase. Notwithstanding, Boise could potentially support a second rate increase, if it is made effective no sooner than January 1, 2018, with a stay-out on new rate increases through January 1, 2019.*

3. ***Revenue Requirement: First Rate Period.*** *My testimony supports a rate increase of 1.04% in the first rate period. This recommendation is based on several adjustments and corrections to the Company's filing.*

4. ***Revenue Requirement: Second Rate Period.*** *If approved, consistent with issue 2 above, my testimony could support a rate increase of 1.15% in the second rate period. This recommendation is also based on several adjustments and corrections to the Company's filing.*

5. ***Schedule 48 Rate Design.*** *I propose a rate design for Schedule 48 that will provide the Company with a greater degree of fixed-cost recovery, consistent with the goals of decoupling.*

II. POLICY: ACCELERATED COAL DEPRECIATION

Q. HOW MUCH OF THE COMPANY'S REQUEST IS RELATED TO ACCELERATED DEPRECIATION OF ITS COAL FACILITIES?

A. The Company's proposal to reduce the depreciable lives of Jim Bridger and Colstrip to 2025 represents approximately $9.9 million in Washington revenue requirement. This is nearly 100% of the initial rate increase requested in this docket.[1/] Thus, absent the proposed depreciation change, the Company has no real need for a rate increase.

Q. WHAT FRAMEWORK SHOULD THE COMMISSION USE TO EVALUATE THIS ISSUE?

A. This issue is a policy question. It is a question of whether there are benefits associated with shorter depreciable lives for the Company's coal facilities that exceed the incremental costs to ratepayers associated with higher depreciation expense. From a ratepayer perspective, there could be benefits associated with a shorter depreciable life. For example, the idea of reducing exposure to stranded investment costs is often viewed beneficially. The accompanying rate increase, however, is not—particularly at a time when energy-intensive and trade-exposed industries in Washington should be supported or at least not disadvantaged. As noted in February 2016 by the Northwest Power and Conservation Council ("NW Council"), "[i]ndustrial loads in the Northwest have been slow to return to levels experienced before the West Coast energy crisis."[2/]

Q. WHAT DO YOU RECOMMEND?

A. PacifiCorp's current circumstances favor a shorter depreciation schedule for its coal facilities. In my opinion, economic factors—such as historically low natural gas prices and oversupply in power markets—are resulting in risk that the Company's investment in its coal facilities will become stranded.[3/] In addition, provided that the Company is not

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1/ Exh. No. SEM-3, Page 6.0.1 Total, line 61.

2/ NW Council, Seventh Northwest Conservation and Electric Power Plan at 7-9 (Feb. 10, 2016).

3/ The term "stranded investment" is being used here in a broader sense than is typically used for purposes of direct access programs. It is referring to a scenario in which the coal facilities are no longer economic, necessitating early closure, similar to what happened to the Trojan Nuclear Power Plant in the mid-1990s.

needlessly investing in the facilities, accelerated depreciation can actually reduce rates in the long run, due to declining rate base balances. If the Commission is to approve accelerated depreciation, however, it should also take action to ensure that ratepayers are not paying for unnecessary costs associated with extending the economic lives of the facilities, costs such as the Jim Bridger selective catalytic reduction ("SCR") systems.

Q. WHY SHOULD RATES EXCLUDE COSTS ASSOCIATED WITH EXTENDING THE LIVES OF THE COAL FACILITIES?

A. Accelerated depreciation will certainly reduce the risks associated with stranded investment, but it will do little to protect ratepayers against stranded costs if the Company continues to invest in the facilities as if they will be operated until 2037. Washington ratepayers have little control over whether those facilities continue to operate after 2025. If the Company or other regional stakeholders make the decision to continue operating those facilities until 2037, Washington ratepayers should not be faced with the additional stranded costs as a result of those decisions.

Q. HOW CAN THE COMMISSION ENSURE THAT WASHINGTON RATEPAYERS ARE NOT REQUIRED TO INCUR UNNECESSARY STRANDED COSTS?

A. The Commission could adopt a policy specifying that any investment attributable to operating those facilities after 2025 is not used and useful to Washington ratepayers. Such a policy would be beneficial to Washington ratepayers because it will allow ratepayers to pay off the rate base balance of the facilities, removing those facilities entirely from rates by 2025. If PacifiCorp was not a multi-state utility, a framework adopted in Oregon with regard to the Boardman plant could serve this purpose.[4/] Because, however, Washington ultimately has only limited influence to determine whether those plants will continue to operate after 2025, a policy to remove those facilities from rates by 2025 will do a lot to protect consumers from being burdened with unnecessary stranded costs associated with operating those plants after 2025.

Q. IF THE COMMISSION ADOPTS THIS POLICY, WHAT HAPPENS WITH THE PLANT ONCE FULLY DEPRECIATED?

A. Provided that the plant is fully depreciated and the retirement obligation fully funded, ratepayers will have fully compensated the Company for the rights to the plant. If the Company decides to continue to operate the facilities after that point, as it has indicated in discovery,[5/] it should certainly have the right to do so; but, it would be unfair to Washington ratepayers to pay for the cost of that decision, to the extent Washington determines that customers are better off by retiring the facilities in 2025.

III. POLICY: THE RATE PLAN AND ATTRITION

Q. WHAT IS YOUR RECOMMENDATION ON THE RATE PLAN?

A. The Company's proposal for rate relief through a multi-year rate plan ought to be rejected by the Commission. It is not practical for the Commission to attest to rate reasonableness in the period subsequent to the initial rate year. The request is also a form of single issue

4/ In Oregon, the Oregon Public Utility Commission allowed Portland General Electric Company ("PGE") to reduce the depreciable life for the Boardman coal power facility to 2020, and PGE has committed to close the facility by that date.

5/ See, e.g., Exh. No. BGM-5C at 36 (the Company's 1st Supplemental Response to Public Counsel ("PC") Data Request ("DR") 15).

ratemaking which ought to be supported by a holistic review of the Company's earnings, rather than discrete changes.

If the second period increase is to be approved, I recommend some modifications to the Company's proposal. I do not agree with the proposition that the Commission should modify rates as proposed by the Company, looking at only those aspects of costs expected to increase in the coming years, and ignoring categories of costs that might decline. If it is to be approved, however, I recommend that the second rate period begin January 1, 2018. I also recommend that the Commission issue a stay-out on new rate changes prior to January 1, 2019, corresponding to the timing of the California Independent System Operator ("CAISO") integration project.[6/]

Q. WHY DO YOU RECOMMEND THAT THE SECOND RATE INCREASE BE REJECTED BY THE COMMISSION?

A. Foremost, it is generally impractical for the Commission to approve the reasonableness of rates two years in advance, based on the information known today. Second, the request constitutes disfavored single issue ratemaking. Third, the request is based on unfounded claims of earnings attrition, which have not been appropriately supported by an attrition study.

6/ On April 13, 2015, the Company and the CAISO entered into a Memorandum of Understanding to investigate the possibility of PacifiCorp joining the CAISO as a full Participating Transmission Owner. The Company and the CAISO are currently engaged with regional stakeholder processes, with a timeline to implement a new regional market by January 1, 2019.

Q. WHY IS IT IMPRACTICAL FOR THE COMMISSION TO APPROVE THE REASONABLENESS OF RATES SO FAR IN ADVANCE?

A. There is no way of knowing how the Company's overall cost profile will change between now and the second rate period. The Company has identified several costs that may increase, but there are other costs that may decline between now and then, which cannot be addressed so far in advance of the rate period. For example, it is possible that labor costs may decline by the second rate period; but, the Commission is being asked to approve rates so far into the future, the parties have no meaningful way to analyze what labor expense will be in the second rate period. In addition, most of the increasing costs proposed by the Company consist of forecast capital items, which are so far beyond the end of the test period as to provide no plausible way of meeting the Commission's used and useful and known and measurable standards.

Q. DO THE SECOND PERIOD CAPITAL ADDITIONS MEET THE KNOWN AND MEASURABLE STANDARD?

A. No. The Commission has confirmed its known and measurable policy in several cases, including in the Company's 2014 GRC, where it referred to an earlier order in a proceeding with Puget Sound Energy, as follows:

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in

> power cost projections, but these are few and demand a high degree of analytical rigor.[7/]

Q. HOW DOES THE SECOND PERIOD RATE INCREASE CONSTITUTE SINGLE- ISSUE RATEMAKING?

A. The Company has requested a second period rate increase based upon increased costs associated with a limited set of revenue requirement items, without considering potentially offsetting cost decreases and other customer benefits that may accrue in the rate period. Isolation of a "single issue" in a rate request, or in this case a single set of issues, is disfavored as a matter of policy because, as recognized by the Commission, it distorts the fundamental "matching principle" of traditional ratemaking.[8/] While under traditional ratemaking "revenues and costs are balanced at a common point in time," single-issue ratemaking, by isolating only those costs expected to increase, can result in "over-earning by the company and over-paying by the customer."[9/]

Q. DOES THE COMPANY PROVIDE ADEQUATE SUPPORT FOR A DEPARTURE FROM TRADITIONAL RATEMAKING PRINCIPLES?

A. No. The Commission has stated that it will "disfavor and typically avoid single issue ratemaking."[10/] In order to depart from the "fundamental principles of ratemaking," including the matching principle, the Commission requires "a clear and convincing showing that the Company will be denied any reasonable opportunity to earn its

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7/ WUTC v. Pacific Power, Dockets UE-140762 *et al.*, Order 08 at ¶ 167 (Mar. 25, 2015) (quoting WUTC v. Puget Sound Energy, Inc. ("PSE"), Dockets UE-090704 and UG-090705, Order 11 ¶ 26 (Apr. 2, 2010)); accord WUTC v. Avista, Dockets UE-150204 and UG-150205 (*Consolidated*), Order 05 at ¶ 238 (Jan. 6, 2016).

8/ Re Avista Corp., Docket UG-060518, Order 04 at ¶ 19 (Feb. 1, 2007).

9/ Id.

10/ WUTC v. PSE, Dockets UE-060266 and UG-060267 (*Consolidated*), Order 08 at ¶ 37 (Jan. 5, 2007).

authorized rate of return without extraordinary relief."[11/] In my opinion, especially in light of the Commission's recent order articulating requisite standards associated with attrition adjustments,[12/] the Company has not demonstrated that its single-issue ratemaking approach is warranted based on a claim of earnings attrition.

Q. HAS THE COMPANY PREPARED AN ATTRITION STUDY TO JUSTIFY ITS REQUEST?

A. No. In Avista's recently concluded GRC, the Commission explained that it would "require utilities to demonstrate persuasively that the attrition occurring is outside of their control."[13/] Unlike the Avista GRC, however, the Company's attrition claims are not supported by any actual attrition study. Accordingly, without such quantitative analysis, it is not possible to determine that the Company has met the obligation to "demonstrate persuasively" that alleged second period attrition is outside the Company's control.

Q. IF THE COMMISSION DOES ADOPT A SECOND RATE INCREASE, SHOULD THE TERMS OF THE RATE PLAN BE MORE REASONABLE?

A. Yes. Insofar as the Commission has the authority to approve rates in the second rate period, it ought to have the ability to adopt more reasonable terms than those proposed by the Company. As presently constituted, the Company's second period rate request—essentially comprising single-issue ratemaking, premised on unsupported attrition claims—is a radical departure from both traditional and recently articulated Commission standards. Thus, the Commission would be fully justified in moderating the terms of the Company's request to avoid an unfair and unreasonable rate result.

11/ WUTC v. PSE, Dockets UE-060266 and UG-060267 (*Consolidated*), Order 08 at ¶¶ 37, 39 (Jan. 5, 2007).

12/ See Dockets UE-150204 and UG-150205 (*Consolidated*), Order 05.

13/ Id. at ¶ 119.

Q. WHAT TERMS DO YOU PROPOSE?

A. If the Commission is to approve a second rate increase, I propose that it be effective on January 1, 2018. In addition, given the current timeline of the integration project with the CAISO, I propose that the Commission implement a stay-out on new rate increases through January 1, 2019, which would correspond to the currently proposed implementation date for the new regional market. If the Commission were to adopt these terms, in conjunction with the revenue requirement adjustments described below, the second period rate increase would be more reasonable.

IV. REVENUE REQUIREMENT: FIRST RATE PERIOD

Q. PLEASE PROVIDE A SUMMARY OF YOUR REVENUE REQUIREMENT RECOMMENDATION FOR THE FIRST RATE PERIOD.

A. Even considering its proposal to accelerate depreciation of its coal facilities, the Company has demonstrated little need for a 2.99% rate increase in this proceeding. As detailed in Table 1 below, after several minor corrections and adjustments are applied, the Company does not need a 2.99% rate increase in the first rate period to have an opportunity for fair return. Rather, my recommendation is that a 1.04% rate increase in the first rate period would be more reasonable.

Table 1
Washington Revenue Requirement Recommendation
First Rate Period

	Rate Base	Operating Income*	Revenue Requirement Deficiency
Company Filing	$ 838,124,164	$ 54,518,748	$ 10,746,470
Adjustments From Company Filing:			
A. Jim Bridger Unit 3 SCR Investments	(12,336,974)	489,175	(2,241,065)
B. Bonus Depreciation	(2,441,357)	(22,508)	(251,091)
C. Pro Forma Capital	(2,148,791)	87,781	(394,495)
D. EOP Rate Base	(12,172,852)	(112,226)	(1,251,963)
E. Colstrip O&M	-	635,930	(1,025,462)
F. Transmission O&M	-	704,339	(1,135,774)
G. Pension and OPEB	-	261,129	(421,081)
H. General Office Expense	-	345,537	(557,191)
I. Cholla O&M	-	(63,050)	101,671
J. EIM Costs	(1,882,496)	80,202	(350,928)
K. Hydro Deferral Balance	-	85,913	(138,538)
Balancing	5,690,759	166,161	401,948
Adjusted:	**812,832,453**	**57,177,131**	**3,482,501**
		Normalized Revenues	335,672,661
* Operating Income Excludes NPC		*% Rate Increase*	1.04%

Q. PLEASE PROVIDE AN OVERVIEW OF EACH OF YOUR ADJUSTMENTS.

A. A summary of each adjustment is provided below, followed by testimony on each issue.

a. ***Jim Bridger Unit 3 SCR Investments.*** *Consistent with the policy on coal facilities discussed above, 54.3% of the Company's investment in the selective SCR pollution control system on Jim Bridger Unit 3 should be excluded from rates.*

b. ***Bonus Depreciation.*** *Revenue requirement should be updated to reflect the extension of bonus depreciation in late 2015.*

c. ***Final Pro Forma Plant.*** *Pro forma plant additions should be updated based on actual transfers to plant.*

d. ***End-of-Period Rate Base.*** *The Commission should adhere to the use of average-of-monthly-average ("AMA") rate base, rather* *than approve the Company's proposal to use end-of-period ("EOP") rate base.*

e. ***Colstrip 3 O&M.*** *Operations and maintenance ("O&M") expense associated with Colstrip Unit 3 should be excluded from revenue requirement because Colstrip Unit 3 is not included in Washington rates.*

f. ***Transmission O&M:*** *Transmission O&M expense should be allocated in a manner more consistent with transmission plant using the same methodology as transmission revenues.*

g. ***Pension and OPEB.*** *Pension and Other Post Retirement Benefits ("OPEB") should be updated based on the latest actuarial reports.*

h. ***General Office Expense.*** *Pursuant to the West Control Area Inter-Jurisdictional Allocation ("WCA") Methodology cost allocation manual, General Office Expenses incurred in FERC Account 557 should be allocated based on the System Overhead factor.*

i. ***Cholla O&M.*** *The Company agrees that a certain O&M credit related to the Cholla coal plant in Arizona should be removed from Washington revenue requirement.*

j. ***Energy Imbalance Market ("EIM") Costs.*** *Because EIM benefits are not currently reflected in base net power costs ("NPC"), I recommend that the Commission exclude the costs associated with the EIM from base rates and require the Company to collect those amounts through the Power Cost Adjustment Mechanism ("PCAM").*

k. ***Hydro Deferral Balance.*** *The residual balance in the hydro deferral should be amortized to rates in the first rate period.*

Q. HOW HAVE YOUR ADJUSTMENTS BEEN CALCULATED?

A. My adjustments have been calculated in a "one-off" study. This means that the impact of each adjustment is calculated independently, without reflecting the offsetting impact of other adjustments. Because the impact of many of the adjustments are offsetting, however, a final revenue requirement calculation is performed to incorporate all of the offsetting impacts of various adjustments. As seen in Table 1, above, I have included a balancing adjustment representing the offsetting impacts of all adjustments.

<u>A. Jim Bridger Unit 3 SCR Investment</u>

Q. WHAT IS YOUR PROPOSED RATEMAKING RELATED TO THE JIM BRIDGER UNIT 3 SCR INVESTMENT?

A. Consistent with the policy discussed above, I recommend that the Commission exclude from Washington rates 54.3% of the Company's investment in the SCR system. This percentage was calculated by taking the number of months that the SCRs will be included in Washington rates based on a 2025 useful life, divided by the number of months assumed in the Company's economic analysis.[14/] The basis for this recommendation is to include only the investment attributable to operating the facility until 2025 and to exclude the investment attributable to operating the facility after 2025. The impact of this ratemaking recommendation is a reduction to Washington revenue requirement of $2.2 million.

Q. WHY IS THIS RATEMAKING APPROPRIATE?

A. An acceptance of the Company's full investment in SCR technology at Jim Bridger Unit 3 is also an implicit acceptance of the Company's assumption that the Jim Bridger power facility will continue to operate and will continue to be reflected in Washington rates until 2037. The working assumption of the Company, and the only reason why the SCRs make economic sense, was that "the Company assumes Jim Bridger Units 3 and 4

14/ The 54.3% was calculated as a fraction of 144 months ÷ 265 months. There are 265 months between 11/30/2015 and 12/31/2037, the period assumed in the Company's economic analysis. There are 144 months between 12/31/2025 and 12/31/2037, the period after which the facilities are fully depreciated.

continue operating beyond the end of 2025."[15/] Therefore, if the Commission were to accept the full amount of the SCRs, it would be accepting the assumption that Jim Bridger will continue to operate beyond the end of 2025 and until 2037. Acceptance of this assumption is not consistent with the proposal to adopt accelerated depreciation, and removes many of the ratepayer benefits associated with accelerated depreciation. If the Company continues to invest in those facilities as if they will be operated until 2037, the stranded cost exposure to ratepayers will not be meaningfully reduced.

Q. WHY IS IT APPROPRIATE TO INCLUDE A FRACTION OF THE COST?

A. To the extent that the Company is making investments to extend the economic life of the facility, it should bear the economic risk associated with that investment after the facility is retired from Washington rates. If, as the Company suggests, the SCR investment is economic after 2025, the Company should not be harmed by assuming the risk of that SCR investment after that date. If the Company continues to operate the facility after 2025, it will earn revenues on Washington's former share the facility, which will, provided that the investment is truly economic, allow the Company to recover its investment associated with the period between 2025 and 2037.

Q. ARE RATEPAYERS AT RISK IF THE COMMISSION DOES NOT ADOPT THIS RATEMAKING TREATMENT?

A. Yes. Under a scenario where Washington adopts "coal-by-wire" legislation, similar to what was recently approved in Oregon,[16/] ratepayers could be required to pay for the full

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15/ Exh. No. BGM-5C at 36 (the Company's 1st Supplemental Response to PC DR 15).

16/ The State of Oregon recently adopted Senate Bill ("SB") 1547, the Oregon Clean Electricity Plan, which among other things, eliminates most coal-fired generation from Oregon rates by 2030 and increases RPS requirements to 50% by 2040.

cost of the SCR investment, without having any way to receive benefits associated with that investment after the plant is fully depreciated. Absent my proposed ratemaking, such a scenario would represent a financial windfall to the Company because the Company will have fully recovered its investment in the Bridger SCRs from Washington ratepayers by 2025. Yet, it will have the opportunity to continue to operate the plant, keeping all of the revenues associated with the plant after 2025, without having any investment at risk.

Q. HAS THE COMPANY DEMONSTRATED THAT THE SCRS ARE ECONOMIC, ASSUMING THAT JIM BRIDGER IS REMOVED ENTIRELY FROM RATES IN 2025?

A. No. Over the course of this shortened proceeding, the Company was requested to perform a study demonstrating that the SCRs are economic based on a 2025 end of life for Jim Bridger.[17/] However, in responding to the request, the Company's base case continued to assume that Jim Bridger would operate through 2037.[18/] The Company bears the burden to demonstrate that the SCRs are economic assuming Jim Bridger is removed from Washington rates in 2025, and in this case, it has not done so.

Q. PLEASE SUMMARIZE YOUR RATEMAKING RECOMMENDATION RELATED TO THE JIM BRIDGER UNIT 3 SCR INVESTMENT.

A. I recommend that the portion of the Jim Bridger Unit 3 SCR investment attributable to the time period after 2025 be excluded from rates. This represents 54.3% of the Company's investment. This treatment will ensure that ratepayers are not saddled with unnecessary stranded costs and will appropriately assign the risk of that investment, associated with the time period after 2025, to the Company.

17/ See Exh. No. BGM-5C at 36 (the Company's 1st supplemental response to PC DR 15).

18/ Id.

B. Bonus Depreciation

Q. WHAT IS YOUR ADJUSTMENT RELATED TO BONUS DEPRECIATION?

A. On December 18, 2015, the President signed into law the Protecting Americans from Tax Hikes ("PATH") Act of 2015, which, among other things, extended bonus depreciation through December 31, 2019, subject to a phase-out provision. My understanding is that the Company's filing assumed that bonus depreciation expired on December 31, 2014, and therefore, did not reflect the full amount of benefits related to bonus depreciation expected in the test period following the passage of the PATH Act. I recommend that revenue requirement be updated in a manner that takes into consideration the provisions of the PATH Act, which will reduce Washington revenue requirement by approximately $0.3 million.

Q. PLEASE DESCRIBE THE PROVISIONS OF THE PATH ACT RELATED TO BONUS DEPRECIATION.

A. Under the new PATH Act provisions, 50 percent bonus depreciation will be available for calendar year 2015 through calendar year 2017.[19/] Bonus depreciation will then begin to phase-out, reducing to 40 percent in calendar year 2018, and to 30 percent in calendar year 2019.[20/] Under the current provisions, bonus depreciation is set to expire after calendar year 2019.[21/]

19/ I.R.C. § 168(k).

20/ Id. at (k)(6)(A), (B).

21/ Id.

Q. HOW DID YOU CALCULATE THE IMPACT OF YOUR ADJUSTMENT?

A. I relied on the calculations provided by the Company in response to Boise Data Request 009.[22/] For my final revenue requirement calculation, incorporating both bonus depreciation and AMA rate base, I relied on the Company's response to Boise Data Request 013.[23/]

C. Pro Forma Capital

Q. WHAT IS YOUR ADJUSTMENT RELATED TO PRO FORMA CAPITAL?

A. This adjustment updates the amount of pro forma capital related to the Jim Bridger Unit 3 overhaul to reflect actual transfers to plant, rather than the projections used by the Company in its November 25, 2015 rate filing. The impact of this adjustment is an approximate $0.4 million reduction to Washington revenue requirement.

Q. WHAT ARE THE PRO FORMA CAPITAL ADDITIONS PROPOSED BY THE COMPANY?

A. The Company's first rate request included a series of pro forma plant additions related to the four-year overhaul of Jim Bridger Unit 3, completed in November 2015. The overhaul included a substantial investment in SCR equipment, discussed above, as well as several other more routine investments.[24/]

22/ Exh. No. BGM-5C at 1-5 (the Company's Response to Boise DR 009).

23/ Exh. No. BGM-5C at 6-9 (the Company's Response to Boise DR 013).

24/ See Exhibit No. SEM-5C.

Q. HOW DOES THIS ADJUSTMENT RELATE TO YOUR PROPOSAL REGARDING THE UNIT 3 SCR SYSTEM, DISCUSSED ABOVE?

A. The offsetting impact of the two adjustments has been reflected in my final revenue requirement recommendation. Irrespective of what the Commission determines on the SCR investment, the amounts of pro forma capital reflected in rates should be based on actual capital costs, rather than the Company's overstated projections.

Q. BY HOW MUCH DID THE COMPANY OVERSTATE ITS CAPITAL PROJECTION?

A. The capital projection forecast for the Jim Bridger Unit 3 overhaul was overstated by approximately [redacted] or approximately [redacted] million on a total-Company basis.[25/]

The projected, as well as actual, expenditures associated with the overhaul are detailed in Confidential Table 2, below.

Confidential Table 2[26/]

Forecast and Actual Revenue Requirement of Pro Forma Capital
(on a total-company basis)

Project Description	Actual Additions	Projected Additions	Forecast Variance	Variance %
Jim Bridger Unit 3 Overhaul				
Replace Cooling Tower	[redacted]			
APH Baskets/Reinforcement				
Replace Finishing Superheater				
Burners - Major				
SCR System - Pollution Control				
Jim Bridger Unit 3 Overhaul Project Total				

25/ Exh. No. BGM-5C at 21-22. (the Company's response to Boise DR 62).

26/ Id.

Q. WHY WAS THE ACTUAL INVESTMENT LESS THAN THE AMOUNT FORECAST IN NOVEMBER?

A. While the overhaul project was completed in November 2015, the final accounting for the overhaul had not been completed when the Company filed this case. My understanding is that it often takes a month or two to finalize the transfers to plant associated with major capital projects, due to lags in invoicing and other accounting documentation.

Q. IS IT CONCERNING THAT THE COMPANY OVERSTATED ITS CAPITAL FORECAST?

A. Yes. Given that the project was essentially completed when the Company made its filing, it is concerning that the Company overstated its capital budget by such a magnitude. This calls into question the reasonableness of all of the Company's capital projections, including the capital additions projected for the second rate period. It is a reason for the Commission to adhere to its practice of only including known and measurable capital additions in rate base. As the Commission has stated, its "long-standing practice is to consider post-test-year capital additions on a case-by-case basis following the used and useful and known and measurable standards while exercising the considerable discretion these standards allow in the context of individual cases."[27/]

Q. HOW DID YOU CALCULATE THE ADJUSTMENT?

A. I relied on the Company's response to Boise Data Request 62.[28/]

27/ Dockets UE-140762 *et al.*, Order 08 at ¶ 165 (citing WUTC v. PacifiCorp, Docket UE-130043, Order 05 ¶ 198 (Dec. 4, 2013)).

28/ Exh. No. BGM-5C at 21-22 (the Company's Response to Boise DR 062).

Q. DID YOU INCLUDE REMOVAL COSTS IN YOUR FINAL AMOUNT?

A. No. In discovery, the Company proposed to include removal costs for the construction or installation of new equipment. I have excluded these costs from my adjustment.

D. EOP Rate Base

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO USE EOP RATE BASE?

A. No. Similar to the 2014 GRC, the Company has proposed to use end-of-period ("EOP") rate base in this proceeding.[29/] The Commission rejected the use of EOP rate base in the 2014 GRC, and I recommend that, consistent with its decision in that case, the Commission continue to require the Company to use average-of-monthly-average ("AMA") rate base to calculate revenue requirement. As discussed below, the use of EOP rate base is inconsistent with how the Company has prepared its pro forma case and would actually reduce revenue requirement if performed consistently. The impact of using AMA rate base is an approximate $1.3 million reduction to Washington revenue requirement.

Q. WHY IS AMA RATE BASE MORE APPROPRIATE?

A. The use of AMA rate base is more appropriate for several reasons. Foremost, the Company has included several other pro forma adjustments that were calculated assuming AMA rate base and that are not compatible with the use of EOP rate base. If all of the Company's adjustments were to be calculated consistently using EOP rate base, it would reduce the revenue requirement. In addition, the Commission has repeatedly

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[29/] Exh. No. SEM-1T at 27:8-13; see also Exh. No. RBD-1T at 8:3-18.

recognized that the use of AMA rate base is a sound method of accounting, more so than EOP rate base.

Q. WHAT ARE SOME OF THE OTHER PRO FORMA ADJUSTMENTS THAT THE COMPANY HAS CALCULATED USING AMA RATE BASE?

A. The Company's pro forma adjustment related to accelerated depreciation (Adjustment 6.4) and pro forma capital additions (Adjustment 8.4) were both calculated assuming AMA rate base. For example, in response to Boise Data Request 031, the Company stated, "The amounts reflected … in Tab 6.4, [related to accelerated depreciation] represent the equivalent of an average-of-monthly-average (AMA) calculation."[30/] In the same response, the Company also states "[t]he Company's only requested post-test-period capital addition is reflected in rate base on an AMA basis for the rate effective period."[31/] Thus, the Company admits that both of these pro forma adjustments were performed on the basis of an AMA calculation.

Q. IS IT CONSISTENT TO USE EOP RATE BASE FOR SOME, BUT NOT ALL, REVENUE REQUIREMENT ADJUSTMENTS?

A. No. Had the Company assumed EOP rate base in its adjustment related to accelerated depreciation, by adjusting the rate base balances for these facilities to be calculated on an EOP basis in the rate period, it would have reduced the impact of that adjustment by $1.5 million. As detailed in Exhibit No. (BGM-6), the use of accelerated depreciation will reduce the rate base associated with Colstrip and Jim Bridger by approximately $79.2 million each year. One of the benefits of accelerated depreciation is a more rapid

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30/ Exh. No. BGM-5C at 17 (the Company's Response to Boise DR 031); see also id. at 23 (the Company's Response to Boise DR 69).

31/ Exh. No. BGM-5C at 17 (the Company's Response to Boise DR 031).

reduction to rate base over time. It is unfair to ratepayers for the Company to use EOP rate base for its existing plant, but then assume AMA rate base for plant subject to accelerated depreciation such that customers do not get the benefit of reduced rate base associated with that proposal.

Similarly, if Adjustment 8.4, related to pro forma plant additions for the Jim Bridger Unit 3 Overhaul, was performed on an EOP basis, it would have reduced revenue requirement by approximately $60,000.

Q. WHY DID THE COMMISSION REQUIRE THE COMPANY TO USE AMA RATE BASE IN THE 2014 GRC?

A. The Commission rejected the use of EOP rate base in the 2014 GRC stating, "[w]e are most concerned in this case that the record is woefully inadequate in terms of demonstrating 'a more refined approach' that assures the Commission that the use of EOP rate base 'is not resulting in violation of the matching principle.'"[32/] As discussed in the 2014 GRC, from an accounting perspective, the use of averages for revenue items—but year-end balances for rate base—violates the matching principle. Because revenues are incurred ratably over the test year, the rate-base against which operating income is compared should also reflect the ratable period over which revenues are measured.

Q. HAS THE COMPANY DEMONSTRATED THAT EOP IS A "MORE REFINED APPROACH"?

A. No. The Company offers little testimony on EOP rate base, other than to reiterate the same arguments made in the 2014 GRC, that an adjustment is necessary to "alleviate

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32/ Dockets 140762 *et al.*, Order 08 at ¶ 150.

attrition and minimize regulatory lag"[33/] This is the same argument that the Company made in the 2014 GRC, where the Company claimed that EOP rate base was "an appropriate method of reducing regulatory lag."[34/]

Q. PLEASE SUMMARIZE THE REASONS WHY THE COMMISSION SHOULD REQUIRE THE COMPANY TO USE AMA RATE BASE.

A. The Company's use of EOP rate base in this proceeding violates the matching principle on many levels. Foremost, the Company has proposed to use EOP rate base for some, but not all, of its pro forma adjustments. The use of EOP rate base in this proceeding results in a conceptually inconsistent revenue requirement calculation and should be rejected by the Commission, in favor of AMA rate base. If the Commission is to approve EOP rate base it should also approve the offsetting adjustments, calculating the impact of accelerated depreciation and pro forma plant on an EOP basis, which will reduce Washington revenue requirement by about $1.5 million.

E. Colstrip 3 O&M

Q. WHAT IS YOUR RECOMMENDATION RELATED TO COLSTRIP UNIT 3 O&M?

A. Colstrip Unit 3 is not included in Washington rates.[35/] It has been excluded from Washington rates since the Company's 1984 GRC, when the unit was originally placed into service.[36/] The Company, however, has included O&M expense associated with Colstrip Unit 3 in Washington revenue requirement. It not fair to Washington consumers

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33/ Exh. No. SEM-1T at 27:10-11. See also Exh. No. RBD-1T at 8:3-18.

34/ Dockets UE-140762 *et al.*, Exh. No. NCS-1T at 6:19-20.

35/ See WUTC v. Pacific Power, Cause No. U-83-57, 1984 WL 1022151, 60 P.U.R.4th 188 at 194-195 (1984).

36/ Id. at 190.

to pay O&M expense for a facility that is not reflected in Washington rates and from which ratepayers receive no benefit. I recommend that Colstrip Unit 3 O&M be excluded from Washington revenue requirement, reducing the rate request by approximately $1.0 million.

Q. WHY WAS COLSTRIP UNIT 3 EXCLUDED FROM RATES?

A. The Company's ownership interest in Colstrip Unit 3 was initially excluded from Washington rates because it was acquired in connection with a power sales agreement with Black Hills Power and Light Company.[37/]

Q. WHY HAS THE COMPANY INCLUDED COLSTRIP UNIT 3 O&M COSTS IN WASHINGTON RATES?

A. In response to Boise Data Request 088, the Company alleges that it has never made an adjustment to remove O&M costs associated with Colstrip Unit 3 from Washington rates.[38/] The Company basically argues that it is appropriate to include Colstrip Unit 3 O&M, simply because it has been doing so for some time.

Q. IS THAT A GOOD REASON TO CONTINUE INCLUDING COLSTRIP UNIT 3 O&M IN WASHINGTON RATES?

A. No. I recognize that the Company has included these O&M costs in revenue requirement for some time now. That does not, however, mean that it is correct to do so. The Company's data responses have identified no instance where the Commission has explicitly reviewed and approved the inclusion of Colstrip Unit 3 O&M in Washington

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37/ Id. at 194-95.

38/ Exh. No. BGM-5C at 24 (the Company's Response to Boise DR 88).

revenue requirement. Accordingly, the Company's past practice does not appear to be a good reason to continue including those costs in Washington rates.

Q. DO WASHINGTON RATEPAYERS RECEIVE ANY ENERGY BENEFITS IN RATES ASSOCIATED WITH COLSTRIP UNIT 3?

A. No. The energy benefits associated with Colstrip Unit 3 are excluded from the Company's net power costs. The Company would likely argue that it would be unfair to include power cost benefits associated with Colstrip 3 in Washington rates, when the accompanying rate base associated with the unit is not. The same argument applies to Colstrip O&M. If consumers are paying for O&M, they ought to get some sort of rate benefit through reduced power costs, or otherwise. Because there is no benefit, there should be no cost.

Q. SHOULD COLSTRIP UNIT 3 ALSO BE EXCLUDED FROM RATES ON THE BASIS OF WCA JURISDICTIONAL ALLOCATIONS?

A. Yes. Because the plant was already excluded from Washington rates, the costs associated with Colstrip Unit 3 were not explicitly addressed as a part of developing the WCA methodology. My understanding is that the Company only has enough transmission capability to deliver approximately 70 MW of power, however, from the Colstrip facility to Washington area loads. This amount of firm transmission is already less than the nameplate capacity of Colstrip Unit 4. Had Colstrip Unit 3 been addressed as a part of the WCA methodology, it is likely that a similar conclusion would have been reached to exclude Colstrip Unit 3 from Washington rates.

Q. DO NET POWER COSTS INCLUDE A RELIABILITY BENEFIT ASSOCIATED WITH COLSTRIP UNIT 3?

A. No. Colstrip Unit 4 is modeled in rates using a derate for forced outages. The Company's net power costs do not provide for replacement power from Colstrip Unit 3, for power lost at Colstrip Unit 4 due to outages.

Q. HOW DID YOU CALCULATE THE IMPACT OF YOUR ADJUSTMENT?

A. I used the raw SAP accounting data provided by the Company in response to Boise Data Request 51. I aggregated O&M expense attributable to the Colstrip location 401000 and then took a ratio of those expenditures, based on the same formula used by the Company to segregate the net plant associated with the facility between the two units. The calculation can be seen in Table 3, below. This amount was then applied as a reduction to expense in my revenue requirement model, subject to revenue sensitive costs. The underlying accounting data has been provided along with my workpapers.

Table 3
Colstrip Unit 3 O&M

FERC Account	Description	Location: 401000 (Colstrip)
500	Operation supervision and engineering.	$ 4,879
501.2	Fuel (non NPC)	420,797
502	Steam expenses	212,716
505	Electric expenses	15,371
506	Miscellaneous steam power expenses	231,169
507	Rents	7,299
510	Maintenance supervision and engineering	56,651
512	Maintenance of boiler plant	593,406
513	Maintenance of electric plant	200,716
514	Maintenance of miscellaneous steam plant	74,315
	Total Colstrip O&M Expense	$ 1,817,319
	Colstrip Unit #3 - Gross Plant %	53.8%
	Colstrip Unit #3 O&M	$ 978,354

F. Transmission O&M

Q. WHAT IS YOUR PROPOSAL RELATED TO THE JURISDICTIONAL ALLOCATION OF TRANSMISSION O&M?

A. The Company currently allocates transmission O&M based on a system generation ("SG") factor. The SG factor is a rolled-in allocation based on the respective demand and energy characteristics of the Company's entire system, both the eastern and western balancing areas. The SG factor, however, is not a reasonable factor to use to allocate Transmission O&M under the WCA Methodology. Because the Company maintains materially less transmission plant in the western balancing area than it does in the eastern balancing area, the O&M incurred with respect to plant located in the WCA is presumably less than the amount allocated in a rolled-in basis. Accordingly, I recommend that transmission O&M be allocated using a factor that takes into consideration the lower level of net plant in the WCA. Specifically, I propose to use the Wheeling Revenue Generation ("WRG") factor, which is the same factor used to allocate firm transmission wheeling revenues. The impact of this adjustment is a reduction to Washington revenue requirement of $1.1 million.

Q. HOW MUCH TRANSMISSION PLANT IS LOCATED IN THE WEST VERSUS EAST BALANCING AREA?

A. Table 4, below, shows the amount of plant located in the west versus the east balancing area. The table also details the respective proportion of loads in both the west and east balancing areas. As can be seen from the table, the proportion of transmission plant in the West is materially lower than the proportion of loads in the West, indicating that a rolled-in allocation is a less reasonable allocation factor than the WRG factor.

Table 4

West Versus East Transmission Plant[39/]

	West	East	Total
Transmission Plant	$ 1,402,907,926	$ 4,021,246,159	$ 5,424,154,086
Accumulated Depreciation	(539,212,238)	(894,782,507)	(1,433,994,744)
Net Transmission Plant	863,695,689	3,126,463,653	3,990,159,341
% of Transmission Plant	27.6%	78.4%	
Loads	20,034,962	39,601,634	59,636,596
% of Load	33.6%	66.4%	

Q. WHY IS THERE LESS TRANSMISSION PLANT LOCATED IN THE WEST?

A. The west side of the Company's system relies heavily on transmission from the Bonneville Power Administration ("BPA"), and less on transmission owned by the

39/ The data in Table 4 is from the "Factors" tab in Company's JAM revenue requirement model. This file was provided in the Company's workpapers.

Company. Under the WCA Methodology, BPA transmission costs are not allocated on a rolled-in basis. Rather, all of BPA transmission costs are assigned to the WCA. BPA's transmission costs reflect O&M incurred by BPA for its facilities, of which Washington consumers pay a larger share than they otherwise would under a fully rolled-in allocation. Thus, if required to pay the Company's fully rolled-in transmission O&M expense for owned facilities, in addition to the full WCA share of O&M embedded in BPA's transmission rates, ratepayers are effectively overpaying for transmission O&M expense.

Q. DOES THE COMPANY ALSO ALLOCATE TRANSMISSION REVENUES ON AN SG FACTOR?

A No. In recognition of the differences between the east and west side of the system, transmission revenues are allocated on the basis of a WRG factor, which is a factor that takes into consideration the relative proportion of transmission plant between the west and east balancing area.[40/]

Q. WHAT DO YOU RECOMMEND?

A. I recommend that transmission O&M expense be allocated on a WRG factor. This treatment better aligns the O&M expense included in rates with the actual O&M cost of the transmission facilities located in the west balancing area.

Q. DOES THE COMPANY AGREE?

A. No. The Company claims that pursuant to the WCA methodology, "expenses that cannot be clearly allocated to a specific control area are then allocated on a System Generation (SG) factor."[41/] This strict reading of the WCA methodology, however, misses the point.

40/ Exh. No. BGM-5C at 26 (the Company's Response to Boise DR 091).

41/ Id. at 27 (the Company's Response to Boise DR 093).

Transmission revenues cannot be clearly allocated to a specific control area, yet the Company has not used the SG factor for those benefits. Instead, the Company uses a methodology that allocates those revenues in proportion to the plant on the respective sides of the system. Similar to transmission revenues, I believe it is appropriate for the Commission to take into consideration the fact that there is less transmission plant, and consequently less O&M expense incurred, on the west side of the system.

G. Pension and OPEB Expense

Q. WHAT IS YOUR ADJUSTMENT RELATED TO PENSION AND OPEB EXPENSE?

A. I recommend that, consistent with the Commission's decision in the Company's 2014 GRC, Pension and Other Post Retirement Benefits ("OPEB") expense be updated to the most recent actuarial reports. In that proceeding the Commission "accept[ed] Public Counsel's recommendation, based on Ms. Ramas' analysis, to reduce Pacific Power's pension expense."[42/]

Q. HOW MUCH PENSION AND OPEB EXPENSE IS THE COMPANY PROPOSING TO INCLUDE IN ITS FILING?

A. The Company has proposed to include approximately $24.7 million for pension expense, on a total-Company basis, and an approximate $4.0 million credit for OPEB expense.[43/]

42/ Dockets UE-140762 *et al.*, Order 08 at ¶ 46.

43 Exh. No. SEM-3, Page 4.2.2.

Q. WHAT WOULD PENSION AND OPEB EXPENSE BE BASED ON UPDATED ACTUARIAL CALCULATIONS FOR 2016?

A. The Company provided its latest actuarial reports in response to Public Council ("PC") Data Requests 52 and 53, as well as updated pension and OPEB expense calculations.[44] Based on the Company's responses to PC Data Requests 52, projected pension expense resulting from the actuarial calculations for 2016 is $22.9 million, approximately $1.9 million less than the amount included in the Company's filing. Based on the Company's response to PC Data Request 53, projected OPEB expense resulting from the actuarial calculations for 2016 is an $8.2 million credit, approximately $4.2 million less than the amount included in the Company's filing.

Q. WHY DO YOU PROPOSE TO UPDATE THESE AMOUNTS?

A. In addition to being consistent with the Commission's order in the 2014 GRC, the Company has proposed to include many other pro forma adjustments in this case meant to increase revenue requirement, without taking into consideration those, such as pension and OPEB expense, that might result in a reduction to revenue requirement. Because the pension and OPEB expense are known and measurable, based on 2016 actuarial reports, it is only fair to ratepayers to include updated pension and OPEB expense.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENT?

A. Based on my initial calculations, updating the Company's pension expense to reflect these new reports results in a reduction of approximately $0.4 million to the Company's Washington revenue requirement. My calculation was simplified, by applying a System

[44] Exh. No. BGM-5C at 38-39 (the Company's Response to PC DRs 52 and 53).

Overhead ("SO") allocation factor to the above variances, and did not run the variances through the Company's full labor model. If the full calculation has not been performed by another party in the proceeding, I will update this amount in cross-answer testimony.

H. General Office Expense

Q. WHAT IS YOUR ADJUSTMENT TO GENERAL OFFICE EXPENSE?

A. The Company incurs general office expenses in FERC Account 557, which it has proposed to allocate to Washington rates using a SG allocation factor. The WCA Manual, however, states that general office expenses are to be allocated using an SO factor.[45] I propose that these costs be allocated in a manner consistent with the WCA Manual, on the basis of the SO factor. This proposal will reduce Washington revenue requirement by approximately $0.6 million.

Q. WHERE DOES THE WCA MANUAL PROVIDE FOR ALLOCATION OF GENERAL OFFICE EXPENSE?

A. An excerpt of the WCA Manual has been included along with my testimony as Exhibit No. BGM-7. As can be seen in Section IV of the WCA Manual, it clearly states "general office – SO," when describing the allocation factor used for general office expenses.[46]

Q. HOW HAVE YOU IDENTIFIED THE AMOUNTS BOOKED TO FERC ACCOUNT 557 AS GENERAL OFFICE EXPENSE?

A. A major portion of the amounts included in FERC account 557 were booked in SAP under as a general office expense, under location "1," "GENERAL OFFICE AND ALL OTHER." Amounts booked to that location were approximately [redacted] in the test

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45/ See Exh. No. BGM-7 at 4.

46/ Id.

period, consisting primarily of payroll and benefits expenses for various organizations involved with power supply.[47/] Because the Company's accounting records identify these costs as General Office expense, I recommend that the expenses booked as such be allocated using the SO factor, consistent with the WCA Manual.

I. Cholla O&M

Q. WHAT IS YOUR ADJUSTMENT TO CHOLLA O&M?

A. The Company's revenue requirement proposal contains a credit of $97,000 related to O&M expense at the Cholla power facility in Arizona. In response to Boise Data Request 054, the Company indicated that this credit was incorrectly allocated to Washington rates.[48/] Removing this credit results in an increase to revenue requirement of $0.1 million.

J. EIM Costs

Q. WHAT IS YOUR RECOMMENDATION RELATED TO EIM COSTS?

A. In the Company's 2014 GRC, the Commission declined to include any of the costs or benefits associated with the Company's ongoing participation in the EIM with the CAISO.[49/] In this case the Company has proposed to include the costs associated with participation in the EIM. Yet, because base net power costs will not be updated, customers will not receive any benefit from the sub-hourly market in base rates. Rather, the benefits will flow through the PCAM, subject to its various design elements.

47/ The underlying accounting data have been provided in Mr. Mullins' confidential workpapers.
48/ Exh. No. BGM-5C at 20 (the Company's Response to Boise DR 054).
49/ Dockets UE-140762 *et al.*, Order 08 at ¶ 89.

Accordingly, consistent with the matching principle, I propose to remove the costs associated with the EIM from base rates, to be recovered through the PCAM, subject to its various design elements.

Q. WHY IS THIS RATEMAKING APPROPRIATE?

A. I believe that it would violate the matching principle to include the costs associated with the EIM in base rates, while excluding the corresponding EIM benefits from base net power costs. When asked about this, the Company stated that it disagreed that the matching principle will be violated because "energy imbalance market (EIM) benefits will flow through the Company's net power costs (NPC) and will be reflected in the annual power cost adjustment mechanism (PCAM) filings."[50/] I agree. In order to be fair, however, I recommend that the costs also be passed through the PCAM.

Q. HOW MUCH BENEFIT HAS THE COMPANY RECOGNIZED AS A RESULT OF ITS PARTICIPATION IN THE EIM?

A. As detailed in Table 5, below, over calendar year 2015 the Company was attributed approximately $26.2 million in benefits related to the EIM. Table 5 details the quarterly benefits associated with the market, calculated by the CAISO in the respective quarterly benefits reports.

50/ Exh. No. BGM-5C at 10 (the Company's Response to Boise DR 014).

Table 5
Actual 2015 EIM Benefits per EIM Quarterly Benefits Report ($millions)
Available at: https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx

Q1	$ 3.82
Q2	7.72
Q3	8.52
Q4	6.17
Total	$ 26.23

These benefits are notwithstanding the Company's claim in the 2014 GRC that EIM costs and benefits were not yet sufficiently known and measurable to include in this filing.[51/] Yet, using a simplified rolled-in allocation based on an SG factor, these benefits amount to approximately $2.2 million in benefits attributable to Washington.[52/]

Q. HOW MUCH REVENUE REQUIREMENT ASSOCIATED WITH EIM IS REFLECTED IN THE TEST PERIOD?

A. Based on its response to Boise Data Request 016, the Company has booked approximately $16.2 million in EIM related capital costs, on a total-company basis.[53/] Based on its response to Boise Data Request 017, the Company has booked approximately $1.8 million in EIM-related O&M expenses on a total-company basis.[54/] These expenditures amount to approximately $0.4 million of Washington revenue requirement reflected in the Company's filing related to the EIM.

51/ Dockets UE-140762 *et al.*, Exh. No. GND-1CT at 7:7-9.
52/ Allocated to Washington using an 8.2% SG Factor.
53/ Exh. No. BGM-5C at 11-12 (the Company's Response to Boise DR 016).
54/ Id. at 13-14 (the Company's Response to Boise DR 017).

Q. WHAT IS YOUR RECOMMENDATION WITH THESE COSTS?

A. I recommend that this $0.43 million of revenue requirement be removed from base rates and recovered through the PCAM mechanism, subject to the various PCAM design elements. In the alternative, I would support a reduction to base net power costs in the amount of $2.2 million, to reflect the benefits discussed above.

K. Hydro Deferral Balance

Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE RESIDUAL BALANCE IN THE COMPANY'S HYDRO DEFERRAL ACCOUNT?

A. In response to Boise Data Request 019, the Company indicated that there is an approximate $132,174 credit balance in the hydro deferral account approved by the Commission in Docket UE-080220.[55/] In response to Boise Data Request 048, the Company indicated that this credit balance was the result of the Company over-collecting the deferral balance.[56/] In Response to Boise Data Request 049, the Company indicated that it would not oppose refunding the credit balance to customers.[57/]

Q WHAT DO YOU PROPOSE?

A. I propose that the Company apply the credit balance as a reduction to the rate increase proposed in this proceeding. Refunding this balance through revenue requirement results in an approximate $0.1 million reduction to Washington revenue requirement.

55/ Id. at 15-16 (the Company's Response to Boise DR 019).
56/ Id. at 18 (the Company's Response to Boise DR 048).
57/ Id. at 19 (the Company's Response to Boise DR 049).

V. REVENUE REQUIREMENT: SECOND RATE PERIOD

Q. WHAT IS YOUR REVENUE REQUIREMENT RECOMMENDATION FOR THE SECOND RATE PERIOD?

A. If the Commission is going to accept a second period rate increase, I recommend that it be made effective no sooner than January 1, 2018, with a stay-out on new rate changes through January 1, 2019. In addition, I recommend that the revenue requirement for the second rate period be reduced based on the following adjustments, detailed in Table 6, below:

Table 6
Second Rate Period Revenue Requirement

	Rate Base	Operating Income	Revenue Requirement Deficiency
Company Filing	$ 36,028,776	$ (3,912,410)	$ 10,550,094
Adjustment From Company Filing:			
A. Jim Bridger Unit 4 SCR Investments	(15,114,029)	691,146	(2,893,664)
B. Update Coal Plant Balances	(23,268,026)	-	(2,739,014)
C. Bonus Depreciation	(6,860,363)	(63,249)	(705,581)
D. Capital Forecast Error	(2,908,569)	135,897	(561,525)
Balancing	4,101,657	(29,853)	233,808
Adjusted:	**(8,020,555)**	**(3,178,470)**	**3,884,119**
		Normalized Revenues	339,155,162
		% Rate Increase	1.15%

Q. PLEASE PROVIDE AN OVERVIEW OF EACH OF YOUR ADJUSTMENTS FOR THE SECOND RATE PERIOD.

A. A summary of each adjustment is provided below, followed by testimony on each issue.

a. ***Jim Bridger Unit 3 SCR Investments.*** *Consistent with the policy on coal facilities discussed above, 56.9% of the*

Company's investment in an SCR pollution control system on Jim Bridger Unit 4 should be excluded from rates.

b. ***Coal Plant Balances.*** *The declining plant balances for Jim Bridger and Colstrip should be updated based on the second rate period.*

c. ***Bonus Depreciation.*** *Revenue requirement should be updated to reflect the extension of bonus depreciation in late 2015.*

d. ***Forecast Error.*** *The plant additions in the second rate period should be reduced to reflect the possibility that proposed amounts are overstated.*

A. Jim Bridger Unit 4 SCRs Investment

Q. ARE YOUR PROPOSING A SIMILAR RECOMMENDATION RELATED TO THE JIM BRIDGER UNIT 4 SCRS, AS DESCRIBED ABOVE FOR JIM BRIDGER UNIT 3?

A. Yes. If the Commission is going to accept accelerated depreciation, it should also exclude the portion of the Jim Bridger Unit 4 SCR investment that is attributable to the period subsequent to 2025. Because of the timing of the Unit 4 SCR system however, I propose that the Commission exclude 56.9% of the facility's rate base from revenue requirement. The basis for this recommendation is the same as that detailed above.

Q. WHAT IS THE IMPACT OF THIS TREATMENT ON THE SECOND RATE PERIOD?

A. Applying this ratemaking treatment will reduce the impact of the Company's revenue requirement by approximately $2.9 million.

B. Coal Plant Balances

Q. WHAT IS YOUR ADJUSTMENT TO COAL PLANT BALANCES IN THE SECOND RATE PERIOD?

A. I propose to recalculate the plant balances associated with the Company's coal plants subject to accelerated depreciation for the second rate period. I propose to recalculate the plant balances using an AMA balance over the period July 1, 2017 through July 1, 2018. This results in a Washington revenue requirement adjustment of approximately $2.7 million the second rate period.

Q. WHY DO YOU RECOMMEND THAT THE COAL PLANT BALANCES BE RECALCULATED?

A. As a result of the Company's proposal to accelerate depreciation for the Colstrip and Jim Bridger power facilities, the rate base balances associated with those plants will decline more quickly than under its existing depreciation schedule. As detailed in Exhibit No. BGM-6, pursuant to the proposal for accelerated depreciation, rate base for these facilities will decline by approximately $79.2 million, each year. In fact, one of the objectives of the proposal to accelerate depreciation for the Colstrip and Jim Bridger power facilities is to gradually reduce the unrecovered investment or rate base associated with those facilities to reduce the risk to customers associated with an early closure. Absent an update of the rate base amounts, consumers are paying the cost of accelerated depreciation, but not receiving the corresponding benefits of declining rate base.

Q. IS IT UNFAIR TO THE COMPANY TO UPDATE THESE BALANCES?

A. No. The Company, through its rate plan proposal, has proposed to include the incremental plant additions associated with its coal facilities, and accordingly, it is only fair that the offsetting impacts associated with declining rate base be reflected in the Company's second rate increase, if one is to be approved.

Q. ARE THERE OTHER CAPITAL ADDITIONS THAT MIGHT OFFSET THE DECLINING RATE BASE ASSOCIATED WITH THE COAL PLANTS?

A. Absent a holistic review of revenue requirement in the second rate period, applying both the known and measurable and used and useful standards, it is impossible to know what all of the offsetting revenue requirement impacts might be in the second rate period. The fact that other capital additions might offset the declining coal balances is actually a reason why the second rate period constitutes single issue ratemaking, and ought to be rejected altogether.

C. Bonus Depreciation

Q. WHAT IS YOUR ADJUSTMENT TO THE SECOND RATE PERIOD REVENUE REQUIREMENT RELATED TO BONUS DEPRECIATION?

A. Similar to the adjustment related to bonus depreciation for the first rate period detailed above, I recommend that revenue requirement be recalculated in the second rate period in a manner that takes into consideration the provisions of the PATH Act of 2015. The Company performed this calculation in response to Boise Data Request 009, which results in an approximate $0.7 million reduction to Washington revenue requirement.[58/]

[58/] Id. at 1-5 (the Company's Response to Boise DR 009).

D. Forecast Error

Q. WHAT IS YOUR ADJUSTMENT RELATED TO FORECAST ERROR?

A. If the Commission intends to approve the capital forecasts that the Company proposes to incorporate into revenue requirement in the second rate period, I propose that an undistributed reduction be applied to reflect the likelihood that the Company's capital forecast is overstated. As detailed in Confidential Table 2, above, the Company overstated its capital forecast for the 2015 plant additions by approximately [redacted] or approximately [redacted] million on a total-Company basis. This overstatement was notwithstanding the fact that the 2015 plant additions were placed into service prior to when the Company filed this case. While I do not agree that the capital in the second rate period meets Washington's used and useful statute, I recommend that, if any pro forma capital is to be approved for the second rate period, the Company's capital budget be reduced by [redacted] the amount that 2015 capital budgets were overstated, to reflect the likelihood that the Company's 2016 budgets are overstated as well.

Q. WHY IS THIS APPROACH APPROPRIATE?

A. The Company bears the burden to demonstrate the reasonableness of its forecast. The fact that the November 2015 capital budget was overstated is an indication that the plant upgrades in the second rate period will be similarly overstated. Because the amounts are not known and measurable, the Commission has no basis to know what the actual amounts placed in service will be. At a minimum, the Company's past forecast variances ought to be used to scale the future plant additions, but in no circumstance should customers bear the full risk that the Company's 2016 forecast will be overstated.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. I have calculated this adjustment by reducing the revenue requirement impact of the Company's second rate period capital adjustments by the above percentage. Applying this reduction to the Company's capital forecasts for the second rate period reduces the Company's rate increase for the second rate period by approximately $0.6 million.

VI. SCHEDULE 48 RATE DESIGN

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR PROPOSAL RELATED TO SCHEDULE 48 RATE DESIGN?

A. This proceeding is unique in that the rate increase entirely surrounds fixed costs. The Company, for example, has not proposed to update net power costs, leading to a result where the rate increase sought by the Company is entirely driven by increases to fixed cost items. In addition, with the Company's move towards decoupling, this case is also marked by efforts to provide the Company with greater certainty surrounding short-term fixed-cost recovery. To account for these unique aspects of the proceeding, I recommend a rate design for Schedule 48 that assigns the rate increase to the fixed-cost billing determinants, rather than to the volumetric energy charges. My rate design proposal for Schedule 48 can be found in Exhibit No. BGM-8 and Exhibit No. BGM-9.

Q. DOES YOUR RATE DESIGN IMPACT ANY RATE SCHEDULES OTHER THAN SCHEDULE 48?

A. My rate design impacts only Schedule 48 and Schedule 47, which itself is a derivative of Schedule 48. No other rate schedules are impacted.

Q. WHAT ARE THE MECHANICS OF YOUR RATE DESIGN PROPOSAL?

A, My rate design will apply the rate increase approved in this proceeding using a common methodology for the entire Schedule 48 rate class, including Schedule 47. Specifically, the methodology will: 1) apply a 25% increase to the basic charges in the rate class, and 2) apply the remainder of the increase attributable to Schedule 48 as a fixed percentage increase to the kW demand charges.

Q. WHY IS IT APPROPRIATE TO APPLY THE RATE INCREASE USING A COMMON METHODOLOGY FOR ALL SCHEDULE 48 CUSTOMERS?

A. The Company has not prepared an updated cost of service study in this case, and instead, has proposed to apply the increase on a fixed percentage basis to each of the rate schedules. In rate schedules other than Schedule 48, each individual customer will receive a varying level of rate increase, based on their load profile, relative to other members of the rate class. The Company's treatment of Schedule 48, however, is somewhat unique because the Company has proposed to single out a particular transmission voltage customer, fixing that customer's rate increase at the same overall fixed percentage increase approved in this case. Given the nature of this case, and the simplistic rate spread proposed by the Company, I do not believe it is fair to single out one particular customer in Schedule 48, fixing that customers rate increase to be the same as the overall increase approved in the case. Rather, I recommend that the rate design be performed using a uniform methodology for the entire Schedule 48 rate class.

Q. WILL YOUR PROPOSAL CAUSE SOME CUSTOMERS ON SCHEDULE 48 TO RECEIVE A GREATER RATE INCREASE THAN OTHERS?

A. Yes. Just as the Company's proposal will cause residential customers with higher monthly usage to receive a higher rate increase than residential customers with low monthly usage,[59/] this rate design proposal will cause Schedule 48 customers with a low load factor to receive a higher rate increase than those with a high load factor. This is fair for two reasons. First, consistent with the move towards decoupling, this proposal will better align the Company's revenue with the recovery of fixed cost. Second, the rate increase in this proceeding largely concerns fixed cost items, so it makes sense to apply the increase to the fixed billing determinants.

Q. HOW IS YOUR PROPOSAL MORE CONSISTENT WITH THE GOALS OF DECOUPLING?

A. Assigning more cost to the fixed billing determinants, such as the demand and the basic charge, will provide the Company with greater certainty surrounding fixed cost recovery, which is a primary goal of decoupling. As discussed by Ms. Steward, "the mechanism focuses on the fixed costs that the Company recovers through its non-NPC volumetric charges."[60/]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO EXCLUDE SCHEDULE 48 FROM THE DECOUPLING MECHANISM?

A. Yes. There are several problems with applying decoupling in a large general service rate class. First, the loads of large customers are primarily driven by economic conditions, not by weather or energy efficiency. It would be unfair to the class to pay additional

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59/ See Exh. No. JRS-5.

60/ Exh. No. JRS-1T at 11:20-21.

fixed costs, simply because economic pressures forced a large customer to close its facility. Second, because these rate classes typically consist of a small number of large customers, intra-class inequity concerns arise with decoupling. To the extent that a single customer's load declines, the fixed costs formerly attributable to that load are reallocated to all customers in the class. Third, because these customers know they are required to pay the fixed costs regardless of whether they are successful in reducing usage, there is often a disincentive to perform energy efficiency, particularly for those classes with few large customers. Finally, as discussed by Ms. Steward,[61/] rate design can often accomplish the same degree of fixed cost recovery and achieve substantially similar objectives as decoupling for these rate classes.

Q. HOW MUCH OF THE REVENUE REQUIREMENT PROPOSED IN THIS PROCEEDING IS TREATED AS A FIXED COST?

A. Based on the Company's proposed mechanism, which will true-up all revenues except those attributable to net power costs,[62/] 100% of the rate increase proposed in this case is treated as a fixed cost. Assigning the rate increase to a volumetric energy charge in Schedule 48 is less consistent with the goals of decoupling. Thus, it makes sense to adopt a rate design that assigns the rate increase as fixed costs to for Schedule 48 customers, rather than to the energy billing determinants.

[61/] Id. at 12:6-13:7.

[62/] See id. at 14:10-16:9.

Q. WHAT ABOUT FIXED COSTS THAT ARE TREATED AS A COST OF ENERGY IN THE COMPANY'S PRIOR COST OF SERVICE STUDY?

A. Decoupling does not differentiate between the fixed costs that are treated as a cost of energy and those that are treated as a cost of capacity. Rather, the mechanism is designed to provide the Company with short-term certainty surrounding all fixed costs. Ms. Steward's Table 2, for example, is slightly misleading because the amounts under "Energy & Reactive" are actually fixed costs that are assigned to energy in the cost of service study.[63/] These are costs which would otherwise be subject to decoupling, and using the same data from Ms. Steward's Table 2, shows that the proportion of fixed costs allocated to Schedule 48 is substantially less than the proportion of revenue recovered under fixed cost billing determinants.

Table 7

Proportion of Fixed Cost Recovery Relative to Allocated Fixed Costs for Schedule 48

	Revenues	Costs
Fixed	27%	57%
Variable	73%	43%

Based on this analysis, it is more reasonable to adopt a rate spread that increases fixed cost recovery to be more consistent with the amount of fixed costs allocated to the class. In addition, it should be noted that no cost of service study was performed for this proceeding. The above analysis, as well as the Company's rate spread proposal, has been based on the cost of service study prepared for the 2014 GRC. The fact that an updated

63/ Id. at 12, Table 2.

cost of service study was not performed for this proceeding should not be factored against Boise's recommendation.

Q. DOES THIS CONCLUDE YOUR CONFIDENTIAL RESPONSE TESTIMONY?

A. Yes.