–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH–

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	)))))))	DPU EXHIBIT 6.0D-RR DOCKET NO. 10-035-124

Artie Powell, PhD

Direct Testimony—Revenue Requirement

Division of Public Utilities

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Artie Powell

Division of Public Utilities

Direct Testimony—Revenue Requirement

INTRODUCTION

Q: Please state your name, employer, title, and address for the record.

A: My name is Artie Powell; I am employed by the Utah Division of Public Utilities (DPU or Division) within the Department of Commerce; I am the Energy Section manger; my business address is 160 E 300 S, Salt Lake City, Utah.

Q: On whose behalf are you testifying in this case?

A: The Division.

Q: Please summarize your qualifications.

A: I hold a doctorate degree in economics from Texas A&M University. Prior to joining the Division, I taught courses in economics, regression analysis, and statistics both for undergraduate and graduate students. I joined the Division in 1996 and have since attended several professional courses or conferences including, the NARUC Annual Regulatory Studies Program (1995) and IPU Advanced Regulatory Studies Program (2005), dealing with a variety of regulatory issues. Since joining the Division, I have testified or presented information on a variety of topics including, electric industry restructuring, incentive-based regulation, revenue decoupling, energy conservation, evaluation of alternative generation projects, and the cost of capital.

SUMMARY

Q: What is the purpose of your testimony?

A: I am recommending three adjustments to the Company's filed case. First, I recommend using the Rolled-in methodology for allocating costs on the inter-jurisdictional level. Using Rolled-in instead of the Revised Protocol reduces the Company's revenue requirement for Utah by about $15 million. Second, I recommend that a portion of the costs associated with the implementation of the Klamath Dam removal settlement be removed from the case. Removing these costs from the case reduces the Company's Utah revenue requirement by about $4.5 million. Third, I recommend that the Company's request for generation overhaul expense on a Utah basis be increased from approximately -$188,962 to $232,951. This increase is the result of changing the methodology used to forecast the test year amount of generation overhaul expense.

Finally, as the manager of the energy section, I will act as the Division's policy witness. The Division believes that each of the adjustments to the Company's revenue requirement recommended in testimony filed by Division witnesses, including consultants, is supportable and represents a reasonable adjustment to the revenue requirement to reflect prudent utility practice. However, the Division is concerned that the cumulative effect of the Division's and others' adjustments in this case could leave the Company with insufficient resources to meet its mandate of providing safe, adequate, and reliable service.

The Division believes the Commission may, and in fact should, consider the cumulative effect of all of the adjustments on the Company’s overall financial health as it establishes the Company’s revenue requirement in this case. A myopic focus on each item in a general rate case may lead to many reasonable adjustments, often small in amount, the combined effect of which ultimately leaves the Company insufficient resources to make needed investments. Failing to consider the cumulative weight of otherwise reasonable adjustments, particularly when Utah’s load is growing relative to the Company’s other jurisdictions, is unwise and could lead to the Company’s future inability to meet its service obligations and would not be in the public interest.

A summary of the Division’s overall revenue requirement position and introduction of the Division’s witnesses is in the testimony of Ms. Brenda Salter, who is managing the Division’s case in this proceeding.

Inter-Jurisdictional Allocations

Q: Can you briefly explain why you are recommending using Rolled-In instead of Revised Protocol for allocating costs to Utah?

A: In Docket No. 02-035-04, the Commission approved a Stipulation supporting the use of the Revised Protocol methodology in conjunction with the Rolled-In methodology and certain rate mitigation measures for allocating or apportioning the Company's costs among the various states. The Stipulation specified that Utah's revenue requirement would be the lesser of Rolled-In multiplied by a rate mitigation cap and the Revised Protocol multiplied by a rate mitigation premium.

For the years immediately preceding the adoption of the Stipulation, Utah's revenue requirement was determined using the Rolled-In methodology. At the time the Stipulation was adopted in 2004, it was expected that for the first several years, the Utah revenue requirement would be greater under Revised Protocol than under Rolled-In. However, in the later years, starting in about 2011, it was expected that the Revised Protocol would produce a revenue requirement less than that produced by Rolled-In. On a present value basis, these differences approximately offset one another so that the long run impact on Utah's revenue requirement would be minimal. That is, in the long run, over the term of the Stipulation, the difference in Utah's revenue requirement from continuing under Rolled-In and Utah's revenue requirement under the Stipulation would be minimal.

The Commission's adoption of the Stipulation was conditional on the realization of the then projected savings of the Revised Protocol methodology relative to the Rolled-In methodology. Specifically, the Commission stated in its order that,

> Our approval of the Stipulation must be conditional. . . . in the long run, it must not result in significantly different impacts on Utah than now expected. If the projected savings to Utah in the later years, which substantially offset the increases in the early

> years, do not materialize, we may consider the further use of the Stipulation.[1]

Unfortunately, the projected savings in the later years have not materialized—Revised Protocol remains, and is projected to remain, above Rolled-In. Thus, the Division does not believe that the Stipulation and the concomitant revenue requirement can be relied on going forward to determine just and reasonable rates in Utah. Therefore, the Division recommends that the Rolled-In methodology be used to determine Utah's revenue requirement in this case and going forward until such time as the Commission approves or adopts an alternative inter-jurisdictional costs allocation methodology.

REVENUE REQUIREMENT IMPACT: ROLLED-IN V REVISED PROTOCOL

Q: What allocation methodology has the Company used in determining its revenue requirement request in this case?

A: The Company has used the Stipulation in determining its revenue requirement request. As previously mentioned, the Stipulation specifies that Utah's revenue requirement would be the lesser of Revised Protocol plus a mitigation premium or Rolled-In plus a mitigation cap. In this case, the revenue requirement under the Revised Protocol plus its premium is less than that under Rolled-In plus its cap. Thus, the basis for the Company's request for an increase in this case, $232 million, is the Revised Protocol plus the

[1] "Report and Order," Docket No. 02-035-04, December 14, 2004, pp. 36-37.

corresponding rate mitigation premium. With that said, the Rolled-In revenue requirement is still less than the Revised Protocol.

Company witness Mr. Steven McDougal presents the revenue requirement for each of these allocation methods.[2] As filed by the Company, under Rolled-In, Utah's revenue requirement is $1,919,640,912. Adding the one percent rate mitigation cap increases this by approximately $19,196,409. The Revised Protocol revenue requirement is $1,931,033,452. The rate mitigation premium is approximately $3,620,688. According to the Company's filing, test year (normalized business) revenues are approximately $1,702,237,831.

Q: What is the impact does using the Rolled-In methodology have on the Company's request for an increase in this case?

A: Looking at Table 1, the difference between the revenue requirement under Revised Protocol, including the rate mitigation premium, and that under Rolled-In is approximately $15,013,228 (=$1,934,654,140 - $1,919,640,912). Adopting Rolled-In in this case, therefore, would decrease the Company's requested increase from $232,416,309 to approximately $217,403,081.

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[2] See Direct Testimony of Steven McDougal, RMP Exhibit_(SRM-3).

Table 1: Revenue Requirement: Rolled-In V. Revised Protocol

Allocation Method	**Base Value**	**Rate Mitigation**	**Total**
Rolled-In	$1,919,640,912	$19,196,409	$1,938,837,321
Revised Protocol	$1,931,033,452	$3,620,688	$1,934,654,140
Test Year Revenues	$1,702,237,831		
Revised Protocol + Premium	$1,934,654,140		
Deficit	$232,416,309		

Q: Would you briefly explain the difference between Rolled-In and Revised Protocol?

A: Rolled-in is a dynamic allocation approach consistent with a single system (for both planning and operation) reflecting current cost-causation of joint-use resources. Rolled-In allocates cost of joint-use resources based on each jurisdiction's contribution to system peak demand and annual energy use.

The Revised Protocol allocation method starts with Rolled-In and then adds four (4) ad-hoc adjustments. The adjustments center around (1) Company owned hydro, (2) Mid-Columbia Contracts, (3) QF contracts, and (4) seasonal loads.

The Embedded Cost Differential Hydro Adjustment, is based on the difference between two calculations: (1) the embedded cost of Company owned hydro including, post-merger costs, and (2) the embedded cost of the rest of the system excluding QF contracts

The Mid-Columbia Contract Embedded Cost Differential adjustment assigns a substantial share of the low-cost Mid-C contracts to the Northwest. Oregon receives the lion's share of this adjustment. The calculation is based on the difference between the Mid-C contracts costs and the costs of All Other resources. (The Revised Protocol states that as long as Oregon continues to support the Revised Protocol, PacifiCorp will not support any change to the hydro endowment adjustments).

Finally, the Revised Protocol situs assigns approved pre-existing QF contracts; and allocates certain resources based on seasonal loads rather than annual loads.

Q: You describe Rolled-In as a dynamic allocation methodology. Would you explain what you mean?

A: Under Rolled-In, the basis for determining a jurisdiction's allocation factors is largely its contribution to system peak. For example, the SG factor as defined in the 2004 Revised Protocol documents is

$$\mathrm{SG_i} = 0.75 * \mathrm{SC_i} + 0.25 * \mathrm{SE_i} \qquad \text{Eq. 1}$$

where

SG_i = the System Generation Factor for jurisdiction I;

SC_i = the System Capacity Factor for jurisdiction I; and

SE_i = the System Energy Factor for jurisdiction i.

Therefore, as a jurisdiction's loads grow relative to the other jurisdictions, its allocation factors will increase. This means that as the loads for one jurisdiction grow relative to the other jurisdictions, that jurisdiction will receive a larger allocated share of new resource costs, as well as receiving a larger share of the allocated costs of the existing resources.

Q: Can you demonstrate the performance expectations of Revised Protocol at the time of adoption of the Stipulation?

A: Yes. I have included as DPU Exhibit 6.1D-RR a forecast of the Revised Protocol relative to Rolled-In developed in the 2004 docket. This exhibit is a copy of an exhibit, Exhibit C, attached to the Commission's order in Docket No. 02-035-04.

As can be seen in the graph, the expectation was that Revised Protocol would be greater than Rolled-In in the initial years, but would be less than Rolled-In in the later years, with the cross-over occurring in approximately 2011. The graph also demonstrates the intended effect of the rate mitigation cap and premium on Utah's revenue requirement.

Q: What was the intent of the Rate Mitigation Cap?

A: In the years immediately preceding the adoption of the Stipulation, Utah's revenue requirement was determined using Rolled-In. The Revised Protocol, therefore, represented in the initial years a shift in costs to the Utah jurisdiction from the other jurisdictions in which PacifiCorp operated. The purpose of the rate mitigation cap was to mitigate the rate impact of the Revised Protocol on Utah ratepayers.

Since adoption of the Stipulation, the Revised Protocol plus its premium, until this rate case, has been greater than Rolled-In plus the cap. Thus, in the last five rate cases, Utah's revenue requirement has included an amount over Rolled-in. Table 2 presents a depiction of these amounts as originally requested by the Company.

Table 2: Rate Mitigation Cap (As Filed by PacifiCorp)

Docket	Revised Protocol	Rolled-In	CAP Percent	CAP Value
04-035-42	1,279,449,499	1,248,104,005	1.50%	18,721,560
06-035-21	1,451,177,035	1,405,246,184	1.50%	21,078,693
07-035-93	1,533,044,193	1,490,798,620	1.25%	18,634,983
08-035-38	1,568,589,411	1,530,674,491	1.06%	16,263,416
09-035-23	1,551,446,173	1,523,737,373	1.00%	15,237,374

Thus, as contemplated under the Stipulation, Utah ratepayers have been paying a premium over Rolled-In since 2004. However, the benefits contemplated under the Stipulation are not likely to materialize in the future. Indeed, in this case, the Revised Protocol is still substantially greater than Rolled-In.

Q: You indicated that the expected savings from Revised Protocol are not likely to materialize. Would you explain your reasoning for this conclusion?

A: Yes. I have included as Confidential DPU Exhibit 6.2D-RR a forecast of Revised Protocol relative to Rolled-In developed by the Company in the multi-state process, MSP, in April 2010. As previously mentioned, the forecast indicates that Utah's Revised Protocol revenue requirement will not fall below that of Rolled-In for the duration of the study period, 2010-2018. In contrast, the 2004 forecast indicated that during this study period, the Revised Protocol would be less than Rolled-In.

History of Allocations

Q: You indicated that over the last several rate cases, the Stipulation governed Utah's revenue requirement but, before adoption of the Stipulation, Utah's revenue requirement was determined under Rolled-In. Would you briefly review the history of the Company's inter-jurisdictional allocations?

A: The Commission's 2004 order adopting the Stipulation provides a concise history of inter-jurisdictional proceedings and decisions in Utah. Therefore, I will briefly highlight what I believe are the most relevant facts and ask that the Commission take notice of its own order in Docket No. 02-035-04 for more details.

According to the Commission's 2004 order, "Prior to the 1989 merger of Utah Power and PacifiCorp (Docket No. 87-035-27), Utah Power served wholesale customers under FERC jurisdiction and retail customers in Utah, Idaho and Wyoming under state jurisdictions."[3] Although the Commission approved the merger, issues surrounding

[3] "Report and Order," Docket No. 02-035-04, p. 19.

inter-jurisdictional allocations were not resolved. However, "The applicants [Utah Power and PacifiCorp] assured the Commission that the merger benefits were so large that under any reasonable allocation method Utah ratepayers would be better off with the merger."[4] Nevertheless, the Commission's 1987 order specified that, "PacifiCorp shareholders were to assume all risks that may result from less than full system cost recovery due to the adoption of different allocation methods by its regulatory jurisdictions."[5]

Q: Are there other relevant facts about inter-jurisdictional allocations you wish to comment on?

A: As previously mentioned, the Commission did not resolve inter-jurisdictional issues in the merger docket—Docket No. 87-035-27. Instead, a task force, the PacifiCorp Inter-jurisdictional Task Force on Allocations, or PITA, was formed to address the allocation issues. PITA developed two inter-jurisdictional allocation methods, Rolled-In and Consensus. The Consensus method differed from Rolled-In in several respects, principally, it provided for divisional—Utah Power and PacifiCorp—assignment of pre-merger plant, and hydro and transmission endowments.

In PacifiCorp's 1990 general rate case, Docket No. 90-035-06, the Commission found that an immediate movement to Rolled-In would unfairly shift costs from the

[4] "Report and Order," Docket No. 02-035-04, p. 20.

[5] "Report and Order," Docket No. 02-035-04, p. 21.

Utah Power Division to the Pacific Division. However, the Commission declined to adopt the Consensus method, but for fairness reasons, did adopt the outcome of the Consensus method. The difference in the revenue requirements between the two methods, approximately $72.7 million, was a fairness premium, which the Commission viewed as the maximum divergence from Rolled-In that it would allow in maintaining inter-jurisdictional fairness.[6]

Expecting the elimination of the hydro and transmission endowments, a key difference between the two methods, over a reasonable time, "The Commission stated that a single-system, Rolled-In allocation method provided the only acceptable benchmark or standard by which alternative allocation methods may be judged."[7]

Q: Has the Commission ever adopted an inter-jurisdictional allocation method?

A: Yes. In Docket No. 97-035-04, the Commission's order, dated April 16, 1998, adopted Rolled-In for apportioning costs to Utah for the purposes of setting rates. The Commission also drew two conclusions relevant for judging the appropriateness of any allocation methodology. First, cost causation should reflect current usage rather than past usage. Second, attempts to achieve merger fairness using ad hoc adjustments

[6] See, "Report and Order," Docket No. 02-035-04, p. 23.

[7] "Report and Order," Docket No. 02-035-04, p. 22.

within an allocation method will likely lead to unintended or inconsistent consequences.[8]

The Commission also reaffirmed its earlier decision to phase out the merger fairness premium over time. To this end, the Commission established a five-year schedule beginning in 1996 through 2000. The intent was that starting in 2001, some twelve years after the merger of Utah Power and Pacific Power, Utah's revenue requirement would be based on Rolled-In.

Q: Did Utah move to Rolled-In in 2001 per the Commission's order in Docket No. 97-035-04?

A: Actually, Utah moved to Rolled-In with the conclusion of the 1997 general rate case, Docket No. 97-035-01.

The Committee of Consumer Services, now the Office of Consumer Services, and the Division filed to initiate a general rate case on February 12, 1997. However, because of legislative action, which froze the Company's rates on an interim basis, rates did not go into effect until March 1, 1999. As of that date, March 1, 1999, it was determined that a total refund of $111.5 million was owing to customers. The Commission also determined that the then present value of the remaining merger fairness premium it had established in Docket No. 97-035-04 was equal to $71.24 million. Using part of the

[8] See, "Report and Order," Docket No. 02-035-04, p. 24.

refund to "buy-out" the remaining portion of the merger fairness premium presented an opportunity for an earlier movement to Rolled-In, which the Commission ordered. Thus, the rates that went into effect on March 1, 1999, were based on the Rolled-In method plus the remaining (present) value of the merger fairness premium.

Rates were also set on the Rolled-In methodology in three subsequent rate cases, Docket Nos. 99-035-10, 01-035-01, and 03-035-02.

Q: If the Commission adopted Rolled-In in the in the 1998 general rate case, and used Rolled-In in several subsequent cases, what gave rise to the Revised Protocol and the use of the Stipulation to set rates in Utah?

A: In its order, dated November 23, 1999, in Docket No. 98-2035-04, the Commission approved the acquisition of PacifiCorp by ScottishPower. As part of the approval, the Company again assumed the risk of cost recovery arising from different inter-jurisdictional allocation methods utilized among the various state jurisdictions.[9]

However, on December 1, 2000, in Docket No. 00-035-15, the Company filed an application seeking approval of a corporate restructuring creating six distribution companies, one for each of the six state jurisdictions, a generation company, and a service company.[10] In its application, "The Company stated the continued gridlock over

[9] See, "Report and Order," Docket No. 02-035-04, p. 26.

[10] See, "Report and Order," Docket No. 02-035-04, p. 27.

inter-jurisdictional allocations resulted in the Company continuing to suffer a material earnings shortfall, and created disincentives for future infrastructure investment."[11]

It is my understanding that most of the states either rejected the Company's initial corporate restructuring proposal or, like the Utah Commission, suspended the schedule in the docket.[12] At the same time the Commission suspended the schedule regarding the corporate restructuring, the Commission initiated (at the Company's request and in cooperation with PacifiCorp's other jurisdictions) the multi-state process, or MSP.[13] A MSP organizational meeting was held in Boise, Idaho on April 10-12, 2002. Subsequently, a series of meetings were held with the other jurisdictions, which led to the development of the Revised Protocol. This in turn led to the Commission adopting the Stipulation.

CONCLUSIONS CONCERNING INTER-JURISDICTIONAL ALLOCATIONS

Q: What can you conclude from this history of inter-jurisdictional allocations?

A: I think there are several important observations to make concerning this history:

- Since the original merger between Utah Power and PacifiCorp, the Commission has consistently used Rolled-In as the standard by which to judge alternative allocation methods;

[11] "Report and Order," Docket No. 02-035-04, p. 27.

[12] "Order Suspending Schedule," Docket No. 00-035-15, April 3, 2002.

[13] "Order on PacifiCorp's Application to Initiate Investigation of Inter-jurisdictional Issues," Docket 00-035-15, April 3, 2004.

- Rolled-In is the only inter-jurisdictional allocation method formally adopted or approved by the Commission;
- Since the original merger, rates in Utah have included tens of millions of dollars above Rolled-In allocations to satisfy merger fairness;
- With the conclusion of the 1997 rate case, Utah ratepayers paid over $71 million to buy-out the remaining fair value of the merger fairness premium;
- The projected benefits under the Revised Protocol methodology have not materialized, and are not likely to materialize;
- The Company has explicitly born the risk of cost recovery arising from differences in inter-jurisdictional allocation methods; and
- Continued use of the Stipulation adopted in Docket No. 02-035-04 to set rates in Utah will not lead to just and reasonable rates.

Therefore, the Division recommends using the Rolled-In methodology for the basis of setting rates in this case. As previously described, Rolled-In is a dynamic allocation methodology, which appropriately reflects current cost causation. Moving to Rolled-In decreases the Company's revenue requirement request in this case by approximately $15 million.

CURRENT STATUS OF INTER-JURISDICTIONAL ALLOCATIONS

Q: Are you aware that the Company has an open application requesting that the Commission approve modifications to the Revised Protocol?

A: Yes, I am familiar with the Application. The Application, which was filed in the 2002 inter-jurisdictional docket, explains that the participants in the MSP workgroup reached an agreement in principle to amend the Revised Protocol. The agreement with its revisions is referred to as the 2010 Protocol. As explained in the Application, the intent of the amendments is "to allow for a greater movement to a rolled-In allocation methodology, while retaining a Hydro Endowment for the former Pacific Power & Light states of Oregon, California, Washington and part of Wyoming."[14]

The 2010 Protocol contains at least two important modifications to the Revised Protocol. First, the Hydro embedded cost differential (ECD) has been "reduced and limited using a comparison of embedded costs based on resources in place on the Company's system prior to 2005."[15] Second, The ECD is fixed at a levelized value, which is applied respectively to each jurisdiction's revenue requirement under the Rolled-in methodology for the duration of the 2010 Protocol.[16]

As of the filing of this testimony, the schedule pertaining to the 2010 Protocol is, at the request of the Utah parties, under suspension while the parties continue discussions.

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[14] PacifiCorp's Application, "In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues," Docket No. 02-035-04, September 15, 2010, p. 5.

[15] PacifiCorp's Application, Docket No. 02-035-04, September 15, 2010, pp. 5-6.

[16] The duration of the 2010 Protocol is through December 31, 2016.

Q: What is the levelized ECD for Utah under the 2010 Protocol?

A: The levelized ECD value is approximately $1 million for years 2011 through 2016. In other words, if the Commission were to adopt the 2010 Protocol as proposed by the Company, Utah's revenue requirement would be approximately $1 million dollars less than that derived under the Rolled-In methodology. Of course, to be consistent, this would mean a full allocation of all plant on PacifiCorp's system, including the costs of removing the Klamath Dam, which I discuss later in my testimony.

KLAMATH DAM

Q: You indicated in your summary that you were making an adjustment to the Klamath Dam project. Could you explain the nature of your adjustment?

A: According to the Company's testimony, an agreement was reached among some of PacifiCorp's jurisdictions, primarily California and Oregon, and other stakeholders during the FERC relicensing process for the Klamath project. The agreement, the Klamath Project Settlement Agreement or KHSA, specifies, among other conditions, that the Klamath facilities will be removed by 2020.

While Utah was not a party to the settlement discussions, and is not a signatory to the KHSA, the Company is requesting that the removal and other costs associated with the Klamath project be included in this case. Specifically, Mr. McDougal explains that, the Company's adjustment,

> adds the Klamath Project relicensing and settlement process costs into rate base and ongoing operation and maintenance expense associated with the Klamath Project is adjusted to the June 2012 level. Also, consistent with the KHSA, depreciation of all Klamath Project facilities (existing assets, relicensing and settlement process costs, and future capital additions) is set at a level that will fully depreciate the assets by December 31, 2019.[17]

My adjustment removes some of the costs associated with the implementation of the KHSA. Specifically, I recommend that the accelerated depreciation for the additional and existing Klamath capital be removed from this case and reset at the original depreciation rates. I also recommend an adjustment to the Company's proposed depreciation life of the relicensing and settlement costs as well. Finally, I recommend that the Klamath removal surcharge, which is situs assigned under Revised Protocol (and the Company's adjustment) but would be fully allocated under Rolled-In, continue to be situs assigned to Oregon and California for this rate case. These adjustments are detailed in DPU Exhibit 6.3D-RR.

Q: What is the basis for your recommendation to remove the accelerated depreciation of the Klamath project?

[17] "Direct Testimony of Steven R. McDougal: Revenue Requirement and Test Period," Docket No. 10-035-124, January 11, 2011, lines 1357-1362, p. 60.

A: The KHSA was executed on February 18, 2011.[18] However, several approvals or conditions must be met before the KHSA can be implemented. First, under the KHSA California and Oregon must approve recovery of approximately $250 million of the removal costs. Third, Congress must approve funds for removal costs that exceed the $250 million borne by PacifiCorp's rate payers in California and Oregon under the KHSA.

While I consider the first hurdle of obtaining funding in California and Oregon minor considerations, the latter two, and especially obtaining Congress' approval, are more problematic. A decision from the Secretary is not expected until the spring (March) of 2012. If this decision is delayed or if the Secretary determines removal of the Klamath dam is not in the public interest, the KHSA could be derailed. Additionally, although legislation is expected to be introduced into Congress this year, the current economic and political climate raises doubts about its ultimate approval. For these reasons, I recommend that the costs associated with the implementation be removed from this case and be re-introduced in a future case when there is more certainty concerning the implementation of the KHSA. Since the Company has stated it plans on filing annual rate cases for the foreseeable future, the Company can introduce the Klamath issue in the next rate case with little incremental impact on rates.

[18] The Company's testimony identifies the execution date as 2010 (See, Direct Testimony of Dean Brockbank, RMP Exhibit_ (DSB-2)). However, over the summer of 2010, the MSP workgroup working on inter-jurisdictional allocation issues was awaiting the final outcome of the KHSA discussions to analyze the impacts on jurisdictional costs. Thus, I believe there is a discrepancy in the Company's exhibit. Nevertheless, the exact execution date is irrelevant to the argument herein.

Q: You are recommending removing the costs associated with accelerating the depreciation of the Klamath project Are you recommending removing the relicensing and settlement costs described in the Company's testimony?

A: No. According to my understanding, the FERC license for Klamath expired in 2006. Since 2006, the Company has been operating, and will continue to operate, the Klamath project under annual extensions of the license, which is permitted under FERC rules.[19] The Company is seeking relicensing and settlement costs of approximately $74 million on a system basis. This amount is a rate base adjustment and, therefore, is approximately an $11 million to $13 million annual Utah revenue requirement adjustment.[20]

It appears that most, if not all, of these costs would be incurred regardless of which path the Company follows: relicensing or removal. Since these cost would be incurred regardless, and since the Dam is operational, I see no need to remove these costs from the case. Additionally, as noted in the Company's testimony, a substantial portion of the $74 million is AFUDC.[21] If the relicensing costs were removed from the case, the AFUDC would increase in the first year by approximately $6 million, and would continue to accrue interest until a resolution of the Klamath issues in Utah. Again, since the relicensing costs would be incurred regardless of the outcome of the KHSA, I do not

[19] "Direct testimony of Dean S. Brockbank," Docket No. 10-035-124, January 2011, p. 6.

[20] The range is based on the rough rule of thumb for capital additions of approximately 15% to 18% of the rate base adjustment.

[21] "Direct testimony of Dean S. Brockbank," Confidential Exhibit RMP_(DSB-3).

see a need to set aside these costs and allow them to continue to accumulate additional interest that ratepayers would likely pay in the future.

However, I do recommend an adjustment to the depreciation life of the relicensing costs. The Company's request to recovery these costs includes, similar to accelerating the depreciation on existing plant, depreciating these costs over the ten years until the Klamath Dam is removed under the KHSA.[22] I recommend that the relicensing costs be depreciated over 20 years.

Q: Why did you choose 20 years for the depreciation life of the relicensing costs?

A: In his testimony, Company witness Mr. Brockbank presents a cost benefit analysis comparing the two paths: relicensing or the KHSA. The analysis, which demonstrates a slight incremental benefit for the KHSA, uses a 44-year present value period.[23] Therefore, one could argue that the depreciation life of the relicensing costs should be 44 years. However, if the depreciation life is extended to 44 years, and then the KHSA moves forward, the depreciation expense for the relicensing costs would need to be trued up, which could create a substantial rate impact for customers. On the other hand, if the depreciation life were ten years, the annual rate impact, as shown in Mr. McDougal's testimony, would be approximately $3.5 million. I chose 20 years as a compromise between these two bookends.

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[22] See Company Exhibit RMP_(SRM-3), p. 8.12.2.

[23] See Company Confidential Exhibit RMP_(DSB-4).

Q: Can you explain why you have not identified an adjustment amount for the Klamath removal surcharge?

A: Under the Company's Klamath adjustment, the surcharge is already situs assigned to Oregon and California. Since the Division's adjustments are adjustments to the Company's filed request, which is off of the Revised Protocol revenue requirement, there is no need for an additional adjustment. If the adjustments were off of a Rolled-In revenue requirement, where the surcharge is fully allocated, then an adjustment would be necessary.

Q: Will you summarize your adjustments to the Klamath Dam project?

A: Yes. There are two types of adjustments, namely, expense and rate base adjustments. Let me summarize the expense adjustments first.

The Company has requested both to accelerate the depreciation of existing Klamath facilities and to depreciate the relicensing costs over the next ten years. Both of these will increase or add to depreciation expense. The Company is requesting as part of its filing to increase depreciation expense for these two items by approximately $5.5 million on a Utah basis over the base year depreciation expense. Using the same framework provided by the Company in Exhibit RMP_(SRM-3), page 8.12, but removing the accelerated depreciation, I recommend adding $1.6 million. This reduces the Company's depreciation expense on a Utah basis by approximately $3.9 million. (See Table 3)

Table 3: Removal of Accelerated Depreciation—Utah Allocated ($)

	Company Adjustment to Base Year	DPU Adjustment to Base Year	DPU Adjustment to Revenue Requirement
Existing Plant	1,966,276	16,753	-1,949,523
Relicensing	3,543,762	1,594,693	-1,949,069
Total	5,510,039	1,611,446	-3,898,592

Similarly, the Company is requesting to decrease its depreciation reserve with respect to these two adjustments: accelerating the depreciation of the existing plant and the 10 year depreciation of the relicensing costs. The Company's requested decrease of approximately $6.7 million is incremental to the base year. Removing the accelerated depreciation and extending the life of the relicensing yields an incremental decrease to the base year of only approximately $2.9 million. Since depreciation reserve acts as an offset to rate base, the difference between my adjustment to the base year and the Company's, approximately $3.9 million, will decrease the Company's rate base. The impact of this adjustment decreases revenue requirement by approximately $640,000. (See Table 4)

Table 4: Adjustment to Depreciation Reserve—Utah Allocated ($)

	Company Adjustment to Depreciation Reserve	DPU Adjustment to Depreciation Reserve	Difference in Adjustments	Revenue Requirement Impact
Existing	-3,188,353	-1,256,290	1,932,063	-318,790
Relicensing	-3,543,762	-1,594,693	1,949,069	-321,596
Total	-6,732,115	-2,850,983	3,881,132	-640,387

The total impact from my adjustments to the Klamath Dam project decreases revenue requirement by approximately $4.5 million.

GENERATION OVERHAUL EXPENSE

Q: Would you please explain your adjustment to the Company's adjustment for generation overhaul expense?

A: In his direct testimony, Mr. McDougal explains,

> The Company's use of a four-year historical average was approved by the Commission in Docket No. 07-035-93, as was the use of a four-year average of planned expenses for the Company's new gas plants. This treatment, including escalation of the historical components of the average, was utilized in the Company's filings in Docket Nos. 08-035-38 and 09-035-23, but the Commission did not allow escalation to be applied in its final order in Docket No. 09-035-23. The Company continues to believe that the purpose of averaging is to adjust for uneven costs, not to adjust for inflation and that without escalation overhaul expenses

> will be systematically understated. However, consistent with the Commission order, **the Company has not applied escalation prior to averaging in this case**.[24] (Emphasis added)

In fact, a review of the Company's testimony, Exhibit RMP_(SRM-3), pages 4.6, 4.6.1, and 4.6.2 shows that the Company did not apply any escalation or inflation factor in calculating its adjustment. The Company's adjustment is based on a simple average of the generation overhaul expense for the four years 2007 through 2010.

The Division agrees with the Company's conclusion: "averaging is to adjust for uneven costs, not to adjust for inflation and that without escalation overhaul expenses will be systematically understated."

In past rate cases, parties have advocated one of two methods to forecast generation overhaul expense (GOE). The first method, Method 1, inflates the average of four historical values. For example, if G_1, G_2, G_3, and G_4 are the historical annual GOE, then the fifth or test period GOE, G_5, is estimated as,

$$\begin{aligned}\hat{G}_5 &= \frac{(1+\pi)}{4}\left[G_1 + G_2 + G_3 + G_4\right] \\ &= \frac{(1+\pi)}{4}\sum_{i=1}^{4} G_i\end{aligned} \qquad \text{Eq. 2}$$

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[24] "Direct Testimony of Steven R. McDougal: Revenue Requirement and Test Period," Docket No. 10-035-124, January 11, 2011, lines 951-961, pp. 42-43.

where π is the rate of inflation. The alternative method, Method 2, averages the inflated historical values to estimate the test period value. That is,

$$\begin{aligned}\tilde{G}_5 &= \frac{1}{4}\left[G_1(1+\pi)^4 + G_2(1+\pi)^3 + G_3(1+\pi)^2 + G_4(1+\pi)\right] \\ &= \frac{1}{4}\sum_{i=1}^{4} G_i(1+\pi)^{5-i}\end{aligned} \qquad \text{Eq. 3}$$

ECONOMIC CONSIDERATIONS

Of these two methods, economic and statistical (or probability) theory suggests that the Method 2, $\tilde{G}$, is on average more accurate. First, economic theory suggests that in order to compare two values separated by time, the values need to have a common monetary base: the values should be expressed in real terms, where the effects of inflation are taken into account, as opposed to nominal terms. Comparing values expressed in nominal terms can lead to erroneous conclusions. For example, suppose we bought a particular item in the year 2000, for $30; and another person bought the same item in 2010 for $50. Who paid more for the item? In a nominal sense, the second person paid more: $50 is greater than $30. However, a nominal comparison such as this ignores the effect of inflation on the purchasing power of the dollar between the two periods and can lead to erroneous conclusions. The proper comparison would take into account the effects of inflation using a price index—such as the Consumer Price Index—to either deflate the 2010 value to 2000 dollars; or, inflate the 2000 value to 2010 dollars. Suppose the price index in 2000 was 1.00 and in 2010 the price index was 1.75. Then, the $30 price paid in 2000 would be equivalent to $52.50 (=1.75*$30) in 2010. Thus, in this example, the person buying the item for $50 in 2010 actually paid less in real terms than the person paying $30 in 2000.

By inflating each of the historical values to a common base year, in this case the test year, Method 2 properly takes into account the effects of inflation before making a comparison (or forecast) to the test year.

STATISTICAL CONSIDERATIONS

Statistical theory also supports the use of Method 2 over Method 1. To demonstrate this, consider the following specification of the annual generation overhaul expense.

Let the generation overhaul expense, G, be specified as,

$$G_i = H_i + \varepsilon_i \qquad \text{Eq. 4}$$

where

G_i = the actual or observed generation overhaul expense for period "i";

H_i = the base or unobserved (unknown) generation overhaul expense for period "i";

ε_i = a random error (shock) term with a mean zero and standard deviation σ_ε; and

$H_i = H_{i-1}(1 + \pi)$.

On average, under this specification, Method 1, $\hat{G}_5$, will underestimate the GOE in the test period, whereas, Method 2, $\tilde{G}_5$, will on average equal the test period value. That is,

$$E(\hat{G}_5) = \theta H_5 \leq H_5 \qquad \text{Eq. 5}$$

where E(·) is the linear expectation operator[25], and θ is a constant between zero and one:

$$\theta = \frac{1}{4}\left[1 + (1+\pi)^{-1} + (1+\pi)^{-2} + (1+\pi)^{-3}\right] \qquad \text{Eq. 6}$$

Whereas,

$$E(\tilde{G}_5) = H_5 \qquad \text{Eq. 7}$$

DPU Exhibit 6.4D-RR provides a derivation or demonstration of Equations 5 and 7.

As can be seen, Method 2 will on average yield a more accurate result and, thus, is the preferred method for forecasting the GOE for the test year. Therefore, I recommend that the Commission adopt this methodology for forecasting the GOE.

GOE MODEL SIMULATION

Q: Do you have any other evidence that Method 2 is likely to provide a better estimate of the test year level of generation overhaul expense?

A: Yes. I have simulated the two estimation methods for the model previously defined. Since the simulation is relatively large—10,000 replications—I provide the full

[25] The expectation operator is defined in DPU Exhibit 6.4D-RR.

simulation only in electronic form as part of my pre-filed testimony. However, a summary of the simulation is provided in DPU Exhibit 6.5D-RR attached to my testimony.

The simulation confirms the conclusions drawn from the statistical modeling, namely, Method 2 provides a better estimate of the test year value. A summary of the simulation results are in Table 5.

Table 5: GOE Model Simulation Results

	Average Estimate	Minimum	Maximum	RMSE	Number Under Estimated	Percent Under Estimated
Method 1	1,078	987	1,166	5,627	9,496	95%
Method 2	1,126	1,031	1,218	3,094	5,046	50%

To perform the simulation I chose a value for year 1's base or unobserved value, H_1, of 1,000 and an inflation rate of three percent. Given the model specified herein, these assumptions yield a fifth year base value, H_5, of 1,126, which is the value to estimate using the first four values. To generate the observed values, G_i, for the four historic years, I used the RAND() function in EXCEL© to generate random deviates, which were added to the four historic values.[26]

Under these conditions, Method 1 underestimates the fifth year value 95% of the time; whereas, Method 2, underestimates the fifth year value as expected approximately 50% of the time. The root mean squared error, RMSE, of the estimates from the two methods also indicate that Method 2 provides a better estimate on average—the RMSE for Method 1 is approximately two times as large as the RMSE for Method 2.[27]

GOE RECOMMENDATION

Q: Is your adjustment to the generation overhaul expense based on Method 2 as you have described?

A: Yes. After updating the New Plant GOE for the most current data available, I inflate the historical values to a common base year and then average the values to arrive at an estimate of the test year value. My adjustment is then incremental to the Company's

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[26] The RAND() function generates random values on a uniform distribution between zero and one. To simulate the variation in generation overhaul expense, I multiplied this function by 200 and subtracted 100: RAND()*200 - 100. This allows for a variation of approximately 10 percent around the base values. The performance of Method 2 relative to Method 1 will improve with smaller variations around the base values; and will worsen with larger, say 25%, variation. Nevertheless, Method 2 will continue to outperform Method 1.

[27] The RMSE is a common statistical measure of the accuracy or precision of an estimator and is defined as the square root of the average squared deviations of the estimates around the true value being estimated. The RMSE is similar to the sample standard deviation: $\sqrt{\sum_{i=1}^{n}(X_i - \bar{X})^2 / n}$. The smaller the RMSE the more accurate the estimate, that is, the smaller is the variation of the estimate around the true value.

adjustment as presented in Mr. McDougal's direct testimony, Exhibit 3, page 4.6, and is summarized in Table 6 below.

Table 6: Utah Allocated Generation Overhaul Expense

	Company	Company Updated	Using Method 2 (and Updated Data)
GOE – Steam	-723,363	-723,363	-216,022
GOE – Other	534,401	411,378	448,973
Adjustment	-188,962	-311,985	232,951

The Company has requested a decrease to the base year GOE of $188,962. Using the basic framework in the Company's adjustment as presented in Exhibit RMP_(SRM-3), the adjustment would increase GOE for the base year by $232,951. In other words, using the updated data and applying Forecasting Method 2 increases the Company's adjustment by approximately $421,913 (=232,951 – (-188,962)). (See DPU Exhibit 6.6D-RR).

Q: What inflation rate did you use to escalate the historical values when applying Method 2?

A: I used an inflation rate derived from the Global Insight inflation indices or factors provided by the Company in Confidential Exhibit RMP_(SRM-4). The factors I used are the factors for maintenance respectively for Steam and Other production. Specifically, I used the factors for the 12 months ending June 2010, the Company's base year, and for the 12 months ending June 2012, the test year, to calculate a 24 month average inflation rate. I annualized this inflation rate and applied it to the historical values as described under Methods 2 in DPU Exhibit 6.4D-RR. (See DPU Exhibit 6.5D-RR)

Q: Does that conclude your direct testimony?

A: Yes it does.