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Issues:	Fuel Adjustment Clause Sharing Mechanism
Witness:	Lena M. Mantle
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Surrebuttal Testimony
File No.:	ER-2011-0028
Date Testimony Prepared:	April 15, 2011

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

UNION ELECTRIC COMPANY
d/b/a AMEREN MISSOURI

FILE NO. ER-2011-0028

Jefferson City, Missouri
April 2011

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase its Annual Revenues for Electric Service)))	File No. ER-2011-0028

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on her oath states: that she has participated in the preparation of the following Surrebuttal Testimony in question and answer form, consisting of 18 pages of Surrebuttal Testimony to be presented in the above case, that the answers in the following Surrebuttal Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

Lena M. Mantle

Lena M. Mantle

Subscribed and sworn to before me this 15th day of April, 2011.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer

Notary Public

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d/b/a AMEREN MISSOURI

FILE NO. ER-2011-0028

Q. Please state your name and business address.

A. My name is Lena M. Mantle and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. Are you the same Lena M. Mantle that contributed to the Staff Revenue Requirement Report file on February 8, 2011, in this case?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. I will provide responses to the Fuel Adjustment Clause (FAC) rebuttal testimony of Ameren Missouri witnesses regarding Staff's recommended change to the sharing mechanism of Ameren Missouri's FAC. The witnesses that I will respond to are Steven M. Wills, Jaime Haro, Lynn M. Barnes and Gary M. Rygh. Staff witness David Roos is providing rebuttal testimony regarding proposed changes to the FAC tariff sheets.

Surrebuttal to Steven M. Wills' Rebuttal Testimony

Q. Mr. Wills states in his rebuttal testimony that Staff was reluctant to acknowledge that Ameren Missouri erroneously calculated the net base fuel costs (NNBFC) rate on Original Tariff Sheet No. 98.5 the Commission approved in Case ER-2008-0318 (p. 22, l. 12-13). Is he correct?

A. No. However, it did take several meetings and communication over more than a year before Ameren Missouri provided sufficient information and explanation for Staff to be able to confirm Ameren Missouri had not calculated the NBFC rates Ameren included in Original Tariff Sheet No. 98.5 as Staff had originally understood them to have been calculated Staff understands now Ameren Missouri did not account for losses between generation and transmission when it calculated the NBFC rates that appear on Original Tariff Sheet No. 98.5.

Ameren Missouri first notified Staff in November of 2009 it believed the NBFC rates were wrong by informing Staff Auditors. At that time, Staff was preparing its direct case in Ameren Missouri's then pending general electric rate increase case, File No. ER-2010-0036. It was Staff's position then, as it is now, that the NBFC rates that were then in effect, having been approved by the Commission and included in Ameren Missouri's published tariff, should not be changed. Staff continued to talk with Ameren Missouri because it wanted the NBFC rates in the pending rate case, File No. ER-2010-0036, to be calculated correctly.

Q. When did Staff understand that the methodology Ameren Missouri had used in calculating the NBFC rates in Case No. ER-2008-0318 did not account for losses between generation and transmission?

A. As stated in Staff's Revenue Requirement Cost of Service Report, Staff did not fully understand why Ameren Missouri's calculation of the NBFC rates did not account for losses between generation and transmission until January 2011.

Q. Why did it take until January 2011 for Staff to fully understand why Ameren Missouri's calculation of the NBFC rates did not account for losses between generation and transmission?

A. The short answer is communication issues. Ameren Missouri made changes in information it was reporting to Staff without informing Staff of the changes and it did not take issue with Staff testimony in a rate case. The critical piece of information relating to the issue is the appropriate kWh loads used to calculate the NBFC rates. Because net system input should be reported at the generation level, Staff should be able to use the hourly net system input loads Ameren Missouri submitted to Staff monthly, as required by 4 CSR 240-3.190(1)(C), for those kWh loads. However, without notifying Staff, Ameren Missouri much earlier had changed its monthly 4 CSR 240-3.190(1)(C) submissions to provide the hourly load requirement at the transmission level. Ameren Missouri calls this Net System Output. As a result, Staff conducted its analyses in both Case No. ER-2007-0002 and Case No. ER-2008-0318 using Net System Output instead of Net System Input. Even though Staff identified in its Staff reports in these cases that it was using what Staff thought was Net System Input, Ameren Missouri did not notify Staff that what Staff had used was actually Net System Output.

In addition to the change in what Ameren Missouri was submitting, Staff testified in both Case No. ER-2007-0002 and in File No. ER-2008-0318 on Ameren Missouri's average annual loss factor. It was Staff's testimony that applying this loss factor to the normalized, annualized customer class usage, would result in the annual electric energy requirement at generation of Ameren Missouri's retail and municipal contract customers. Ameren Missouri did not provide any rebuttal testimony informing Staff that Staff's loss factor was at transmission, not at generation.

As a result, when Ameren Missouri asserted its calculation of the NBFC rates were erroneous, but that Staff's fuel run was correct, it was difficult for Staff to understand why, until Ameren Missouri provided a full explanation.

Q. Are you responding to anything else Mr. Wills states in his rebuttal testimony?

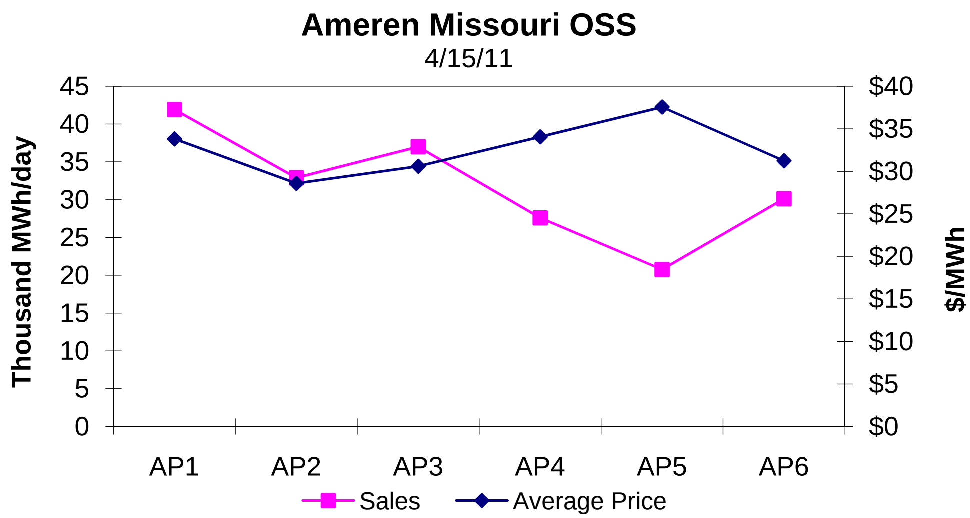
A. No, I am not. However, Staff witness David Roos does provide additional response to Mr. Wills rebuttal testimony.

Surrebuttal to Jaime Haro's Rebuttal Testimony

Q. How do you respond to Ameren Missouri witness Jaime Haro's rebuttal testimony regarding Ameren Missouri's incentive to make off-system sales?

A. I appreciate his thoroughness in describing the impact of increased usage and the timing of planned outages at generation plants had on Ameren Missouri's ability to make off-system sales in the first five accumulation periods. This is why page 115 of the Staff Revenue Requirement Report filed on February 8, 2011 ("Staff Report") contains a statement regarding formulating conclusions based on limited data and information.

Since the Staff Report was filed Ameren Missouri filed to change its fuel and purchased power adjustment again in File No. ER-2011-0317 on March 25, 2011. I have the updated Ameren Missouri OSS graph shown on page 114 of the Staff Report with information from AP 6 as shown below.



The average daily MWh sold in AP 6 increased while the average price per MWh dropped below the average price per MWh in AP 4 and AP 5, to approximately the same as the average price in AP3.

Q. Did you update the other graphs that were in the Staff Report?

A. Yes, I did. Those updated graphs, along with the graph from my work papers that Mr. Haro included in his rebuttal testimony can be found on Schedule LMM-S1.

Q. Mr. Haro states on page 2, line 12, that you contend that Ameren Missouri had a "lack of incentive" to make off-system sales. Is that what you were contending in the Staff Report?

A. No, it is not. The report does state that the amount of off-system sales and the price of the off-system sales from the first 5 accumulation periods show a pattern that might be expected of a utility that had little or no incentive to make off-system sales. The report then lists other factors that might have also influenced the amount of off-system sales made. Mr. Haro explained how those factors had indeed affected the off-system sales potential.

However, the information on the amount of off-system sales and average price of off-system sales was not the only factor consider when recommending a change in the incentive mechanism. Staff recommended changing the incentive mechanism based on the five factors listed on page 111 of the Staff Report and reproduced here:

> 1) Ameren Missouri's request in this case to rebase its FAC NBFC;
>
> 2) Ameren Missouri's request for additional revenue in its true-up filing for AP1 based on an assertion that the FAC NBFC established in the 2008 rate case are too high;
>
> 3) The results of Staff's prudence audit that included AP1 and AP2 where Staff concluded Ameren Missouri was imprudent for excluding from its FPA calculations costs and revenues associated with its contract sales of energy to American Electric Power Operating Companies ("AEP") and to Wabash Valley Power Association, Inc. ("Wabash");
>
> 4) Information Ameren Missouri provided in its monthly FAC filings and in its filings to change its FPA information including its fuel and purchased power costs, and OSS revenues; and
>
> 5) The impact on Ameren Missouri's net income of changing the sharing percentage in its FAC sharing mechanism.

Q. In his rebuttal testimony Mr. Haro states that no party provided evidence that Ameren Missouri lacked incentive to act aggressively in the off-system sales market. Is that necessary to change the incentive mechanism?

A. No, it is not. Due to the limited time that Ameren Missouri's fuel adjustment clause has been in effect, there is little information regarding the actions, or lack thereof, of Ameren Missouri at different incentive levels. While Mr. Haro may sincerely believe that Ameren Missouri would not have acted differently, there is no way to know if Ameren Missouri would respond differently to a different incentive mechanism. If the Commission wants to understand whether or not a change in the mechanism would actually result in a change in behavior, it has to first change the mechanism.

Surrebuttal to Lynn M. Barnes Rebuttal Testimony

Q. Do you agree with Ameren Missouri witness Lynn M. Barnes' rebuttal testimony on page 3, lines 18-19, that the dispute in File No. EO-2010-0255[1] is related to a difference in interpretation of the FAC rider approved in File No. ER-2008-0318?

A. While it is "related" to a difference in the interpretation of the FAC rider, it is the position of Staff that Ameren Missouri acted imprudently when it excluded costs and revenues associated with the American Electric Power Service Corporation (AEP) and Wabash Valley Power Association (Wabash) contracts from the calculation of net fuel and purchased power costs recoverable through Ameren's Commission authorized Fuel Adjustment Clause (FAC). Ameren's action in regards to the treatment of the cost and revenues associated with the AEP and Wabash contracts was unlawful and harmed its retail customers. It is much more than just a disagreement regarding the interpretation of tariff language.

Q. Are you suggesting, as Ms. Barnes asserts on page 3, line 23 – page 4, line 2, that the FAC sharing mechanism should be changed because Ameren Missouri entered into these contracts in the wake of the loss of load from Noranda Aluminum?

A. No, I am not. As Staff has repeatedly stated, and Ms. Barnes points out in her rebuttal testimony on page 4, line 21 through page 5, line 1, Staff believes that Ameren Missouri was prudent in entering into the AEP and Wabash contracts, but it was imprudent in the treatment of the expenses and revenues associated with those contracts. It is Staff's position in this case, that Ameren Missouri may have acted differently regarding the revenues from these contracts had the incentive mechanism been different.

[1] In the Matter of the First Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company d/b/a AmerenUE.

Q. With respect to this dispute, on page 5, lines 9-13 of her rebuttal testimony, Ms. Barnes suggests that it is Staff's premise that if Ameren Missouri had been responsible for a 15% share of changes in net fuel costs then it would not have entered into power supply contracts to replace the load lost because Ameren Missouri would have been able to keep 15% of any off-system sale that could have been made using the volumes not being taken by Noranda. Is this a correct characterization of Staff's position?

A. No, it is not. This statement makes no sense to me. However, from the rest of her answer to that question in her rebuttal testimony, I can surmise that Ms. Barnes was trying to characterize Staff's position to be that Ameren Missouri would not have excluded costs and revenues associated with those contracts from the calculation of net fuel and purchased power costs recoverable through Ameren Missouri's FAC if the sharing mechanism had allowed Ameren Missouri to retain 15% of the revenues from these contracts.

Q. Is it Staff's position that Ameren Missouri's actions would have been different had the incentive mechanism been the 85%/15% incentive mechanism recommended by Staff in this case?

A. It is Staff's position that no one knows. Although Ms. Barnes states on page 5, line 17-18 that Ameren Missouri's actions would have been the same regardless of the sharing mechanism, I believe that it is very likely that Ameren Missouri's actions would have been different had the incentive mechanism only passed 5% of the revenues from these contracts to the ratepayers instead of 95%.

Q. On page 4, line 11, of her rebuttal testimony Ms. Barnes asserts "Ms. Mantle is suggesting that if the sharing mechanism had been different that this error [in the calculation of the NBFC rate which is the subject of the dispute in File No. ER-2010-0274[2]] would not have occurred." Is Ms. Barnes assertion correct?

A. No, it is not. Again no one knows what would have happened if the incentive mechanism had been different from 95%/5%. Staff's is recommending the 85%/15% sharing mechanism to give Ameren Missouri a greater incentive than the 95%/5% sharing to look for and find these types of errors before it files tariff sheets.

Q. On page 6, line 6 of her rebuttal testimony, Ms. Barnes says Ameren Missouri viewed the issue of the NBFC rate the Commission approved in Case ER-2008-0318 to be the result of a "simple mistake" unrecognized both Staff and Ameren Missouri, which Staff would agree should be corrected. How did Staff respond when Ameren Missouri raised the issue?

A. First, Ms. Barnes testimony on its position about correcting the mistake and expectations of Staff's response appears to Staff to have no bearing on the issue of whether a different sharing mechanism would give Ameren Missouri more incentive to find such mistakes. In any event, Staff and Ameren Missouri reached an agreement in Ameren Missouri's then pending general electric rate case, File No. ER-2010-0036 that resolved the issue prospectively. As I stated earlier, the issue of relief for a past period is pending before the Commission in File No. ER-2010-0274. And, as I discussed earlier, Ameren Missouri did not make a "simple mistake." It was virtually impossible for Staff to recognize the error at the time that the tariff sheet was filed since Ameren Missouri had repeatedly misrepresented information to Staff and failed to inform Staff that it had incorrect assumptions in its analyses presented in Staff's testimony in Case Nos. ER-2007-0002 and ER-2008-0318.

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[2] In the Matter of Union Electric Company d/b/a AmerenUE's Fuel and Purchased Power Adjustment Clause True-up

Q. Ms. Barnes states page 6, lines 8-12 of her rebuttal testimony that when Ameren Missouri presented the “error” it made in Original Tariff Sheet No. 98.5 in the File No. ER-2008-0318 case to Staff in late 2009, Staff agreed that a mistake had been made but would not agree that it was appropriate to correct the mistake. Is this a correct representation of what occurred?

A. No, it is not and I fail to see how her statements bear on the issue of the appropriate sharing mechanism. As I stated in response to Mr. Wills rebuttal testimony above and in the Staff Report, Staff did not understand the mistake until right before it filed the Staff Report in this case. Further, Staff and Ameren Missouri resolved the issue prospectively in File No. ER-2010-0036, and for one past period it is before the Commission for decision in File No. ER-2010-0274.

Q. Did Ms. Barnes correctly anticipate Staff’s response to this statement in her rebuttal testimony as set out in the footnote on page 6?

A. No she did not. In the footnote, Ms. Barnes states that Staff would argue that there was no mistake. Ms. Barnes may have been confused since, even though it was uncertain a mistake had been made, Staff and other parties entered into a settlement regarding the issue in File No. ER-2010-0036. However, in January 2011, Staff did conclude that Ameren Missouri had made a mistake. Staff and Ameren Missouri filed, on March 3, 2011, a joint Stipulation of Facts in File No. ER-2010-0274 that includes a description of the error made by Ameren Missouri. Staff will soon file its brief in this case explaining Staff’s position.

Q. On page six, at lines 13-15 of her rebuttal testimony, Ms. Barnes states she supposes Staff is implying Ameren Missouri should have been more careful and it would have been more careful if the sharing percentage were greater. Has she accurately stated why you presented testimony about the mistake in NBFC rates?

A. Yes it is. When I look at the great lengths that Ameren Missouri is going through to recover the amount that Ameren Missouri believes that it is due because of an error Ameren Missouri made – an amount of $5 million that Ms. Barnes characterizes as a "small sum" out of total net fuel costs – I do believe that with a greater sharing percentage Ameren Missouri will be more careful.

Q. Ms. Barnes states on page 7, line 18 of her rebuttal testimony that changing the sharing mechanism to increase the Company's portion will result in the disallowance of prudently incurred fuel costs when costs increase between rate cases, or whenever the net base fuel costs are set too low. Is this a fair representation of the sharing mechanism?

A. No, it is not. If postage costs increase above the expense amount set in the most recent case and it costs more for Ameren Missouri to bill its customers, the increased cost of billing is not considered a "disallowance." In Missouri, any recovery in a fuel adjustment clause is a privilege granted by the Commission – not a right. Therefore, in the same way that the increase in postage is not a disallowance, Ameren Missouri's portion of any increase in fuel costs is not a disallowance.

Q. It is Ms. Barnes contention on page 8 of her rebuttal testimony that net base fuel costs are likely to be set at a level that is too low because off-system sales revenues are higher in the case than Ameren Missouri is likely to achieve. How do you respond to this contention?

A. The very first item on the list of factors that Staff reviewed to make a recommendation regarding whether or not to change the sharing mechanism is Ameren

Missouri's request to rebase its fuel adjustment clause. Because it is Ameren Missouri's position that the fuel adjustment clause should be rebased, Staff, in its report, stated that because Ameren Missouri was proposing to rebase, this was not a basis for it recommending a change in Ameren Missouri's sharing mechanism. However, Ms. Barnes' statement leads Staff to re-consider its position. If Ameren Missouri is recommending a level of off-system sales that is lower than what it believes it can achieve, then the sharing mechanism is not great enough for Ameren Missouri to be concerned with getting it right.

Q. Should a showing of imprudence be required before changing a sharing mechanism in a manner that increases the costs that a utility absorbs as suggested by Ms. Barnes on page 8, line 22 and page 9, line 18 of her rebuttal testimony?

A. A showing of imprudence is not necessary before a sharing mechanism can be changed. Section 386.266.1, RSMo. Supp. 2010, provides:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with **incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities**. (emphasis added).

The link the Legislature forged between incentives and fuel and purchased-power procurement is that the Commission may include "features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities," not that if no imprudence is found the "sharing" mechanism should not be changed. The current 95%/5% "sharing" mechanism is such a feature the Commission designed to provide Ameren Missouri with an incentive to improve the efficiency and cost-effectiveness of its fuel and purchased power activities and its off-system sales revenues. Staff believes changing the current 95%/5% "sharing" mechanism to 85%/15% would better incent Ameren Missouri to "improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities." While Ameren Missouri may dwell on the potential impact based on its past experience—where Staff believes it was inadequately incented—it ignores the potential benefits from the 15% of off-system sales revenues it would get under Staff's proposal, a benefit Staff believes better incents Ameren Missouri to "improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities."

Q. Has Ameren Missouri been found to be imprudent in its management of its net fuel costs?

A. At the time that this testimony was written Ameren Missouri has not been found to have acted imprudently. However, the Commission has indicated that it will soon issue an order in the Ameren Missouri prudence audit case.

Surrebuttal to Gary M. Rygh Rebuttal Testimony

Q. How would you respond to Mr. Rygh's statement on page 5, line 1 of his rebuttal testimony that "It was never expected that the major components of the FAC would be called into question in every possible proceeding…"?

A. Mr. Rygh prefaces this remark on page 4 of his rebuttal testimony with his understanding that the FAC was established after an exhaustive regulatory review. It seems incredulous to assume that after "an exhaustive regulatory review" establishing the FAC, the Commission should not review the major components of the FAC in every rate case that occurs after the establishment of a FAC. Section 386.266.4 RSMo, Supp. 2010, which provides the Commission the power to approve, modify or reject also requires the utility to file a general rate case with the effective date of new rates to be no later than four years after the effective date of the Commission order implementing the FAC. All major aspects of a utility's rate schedules along with its costs and expenses are examined in a rate case. There is no reason to expect that the major components of a FAC would not also be examined.

Mr. Rygh seems to contradict this statement regarding the review of major components of the FAC on page 9 of his rebuttal testimony where he states that investors and rating agencies expect the Commission to thoroughly review every aspect of the FAC. Oddly though, Mr. Rygh states that the Commission should just "report on issues found on a regular basis" and let the investors punish Ameren Missouri accordingly by either refusing to provide capital or charging higher costs for capital (page 9 lines 1-6).

However, at the end of his testimony, Mr. Rygh states that investors expect and rely on the Commission to hold Ameren Missouri accountable when it does not perform or does not act prudently.

Q. Did Mr. Rygh provide any workpapers that quantified the increased cost of capital that investment firms, such as his own employer, Barclays Inc., would require to invest in Ameren Missouri if the Commission were to make changes to the FAC?

A. No. According to Staff witness David Murray, Mr. Rygh's employer routinely publishes equity research reports on Ameren's stock. Considering the importance of the cost of capital to the revenue requirement for Ameren Missouri, it would be helpful if Mr. Rygh would provide supporting investment analysis from Barclays' equity research department on the impact the implementation of the FAC had on Barclays' required return for Ameren. This quantified information would be more helpful in defining the cost of capital impacts of FACs rather than generalized statements. Staff could then review this information and provide an opinion on the value Barclays assigns to the FAC and any possible changes to it.

Q. Mr. Rygh contends that interpretational disagreements and "mere" calculation errors should not be used to suggest substantive changes to the FAC on page 5, lines 3-6, of his rebuttal testimony. Again, is this a fair description of the prudence audit case File No. EO-2010-0255 and the true-up case File No. ER-2010-0274?

A. No it is not. Mr. Rygh may place little importance on these cases but they are significant as the utilities and the Commission work to implement FACs in a manner that is fair to both the utility shareholder and the ratepayer, which Mr. Rygh states is the cornerstone of investor confidence for utilities (page 5, lines 22-23).

Q. Are you concerned that changing the sharing mechanism will send negative impressions to investors as listed on page 7 of Mr. Rygh's rebuttal testimony?

A. Yes, I am. However, if investors are as savvy as Mr. Rygh portrays them to be, they will know that the FAC is a new mechanism in the state of Missouri and that it will take time to get it implemented correctly. As for sending the impression that the Commission must believe that Ameren Missouri is not prudently managing its fuel and purchased power costs and off-system sales (page 7 lines 16-17), the Commission decision in EO-2010-0255 is likely to be made before the sharing mechanism in this case is determined and, if the Commission does find that Ameren Missouri was imprudent, it will send a definite impression regarding whether or not Ameren Missouri is not prudently managing its fuel and purchased power costs.

Q. Do you know of recent decisions by other Commissions regarding change in a FAC sharing incentive mechanism?

A. I have not conducted a search for decisions of other Commissions. However, I have become aware of recent orders issued by the Wyoming and Utah Public Service Commissions regarding sharing mechanisms and I have attached the orders to my surrebuttal testimony as Schedules LMM-S2 and LMM-S3. Both apply to Rocky Mountain Power Company. On page 24 of its Order, the Wyoming Public Service Commission found that the reasonable sharing band is one that obligates customers to pay 70% of the difference between actual and base net power costs. The Utah Public Utility Commission, on page 84 of its order, also sets a 70-30 customer-shareholder sharing for Rocky Mountain Power Company.

Q. Mr. Rygh states on page 8 of his rebuttal testimony that a concern of the financial community is that Staff's "surprising" recommendations are occurring outside of the well-established prudency and true-up review process. How do you respond to this statement?

A. First of all, given the Commission rules, a rate case is the only process in which any party can make such recommendations. Secondly, the recommendation should not be too surprising in that Staff has also recommended changes to the sharing mechanisms of the other Missouri electric utilities that have FACs. Lastly, the prudency and true-up process are not "well-established" in Missouri. File No. EO-2010-0255 was the first Ameren Missouri prudence review and File No. ER-2010-0274 is the first true-up case.

Q. On page 10, lines 8-11, Mr. Rygh's states that the financial community might understand a change in Ameren's FAC if there was evidence that Ameren Missouri needed an additional financial incentive to abide by its regulatory mandates or the Company was not competently managing its largest operating expense. If the Commission adopts Staff's recommendation, would this be evidence that the financial community will understand?

A. Yes, it would.

Q. Mr. Rygh states on page 11, line 5, that the current FAC is properly designed. Do you agree?

A. I do not know if it is or not. I do not believe that the Commission or anyone else has enough experience with FACs in Missouri to definitely state that a utility's FAC is properly designed. Just because the utility and the investment community like a certain FAC does not mean that it is properly designed to balance the interest of the shareholder and the ratepayers.

Q. Has the Commission heard from the Ameren Missouri ratepayers regarding the FAC?

A. Yes, it has. Of the 566 public comments in this case, 99 of the comments refer to the FAC. I have read all 566 public comments. I do not remember any person that submitted a public comment saying that they liked the current FAC. While I understand that these public comments do not carry the weight of a witness that provides an affidavit, they are indicative of the ratepayer's position regarding the FAC.

Q. On page 10, beginning at line 16 through line 3, on page 13 of his testimony, Mr. Rygh includes a discussion and several quotes regarding regulatory lag. Did Ameren Missouri propose any changes to its FAC that would reduce regulatory lag?

A. It did not in its direct case. However, in her rebuttal testimony, Ms. Barnes stated that Ameren Missouri agreed with Staff's recommendation to reduce the recovery periods to 8 months. This change, recommended by Staff, would reduce the regulatory lag associated with the FAC.

Q. Are there changes that could be made to Ameren Missouri's FAC that would reduce its FAC regulatory lag even more?

A. Yes. As mentioned in the Staff Report, Ameren Missouri could reduce the time between when an accumulation period ends and a recovery period begins by filing its changes to the FAC a month after the end of the accumulation period instead of two months as it currently does.

Q. Has Ameren Missouri suggested this change?

A. No, it has not.

Q. Mr. Rygh ends his testimony on page 17, lines 10-14, with the following statement:

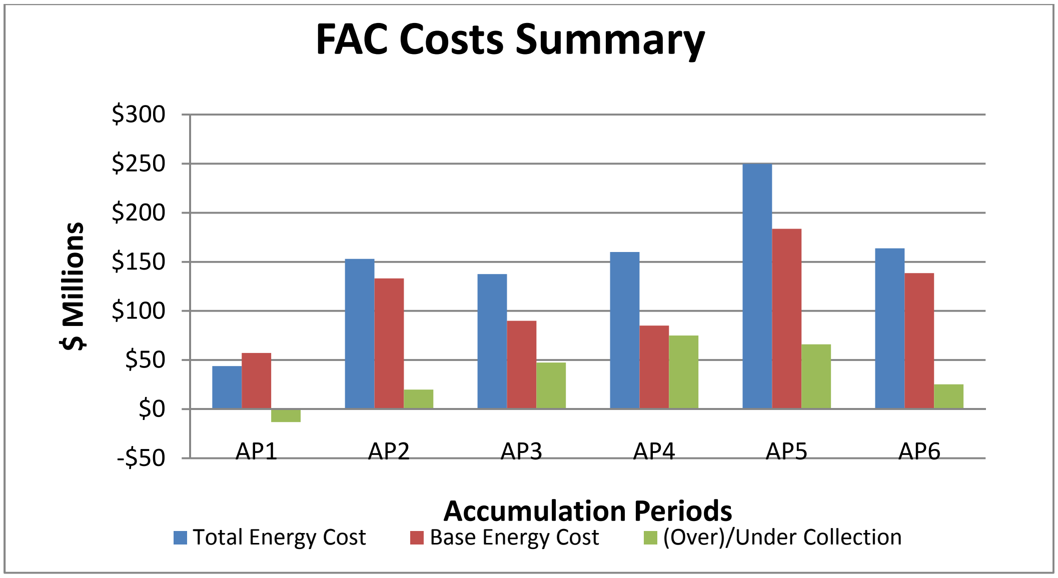
> In summary, the Commission's prior order regarding Ameren Missouri's FAC, coupled with its approval of similar FACs for the other Missouri electric utilities that are eligible to utilize one, suggested that the Commission was on its way to building a track record of consistent, thoughtful and high quality examination of key issues that affect the Company and the ratepayers it serves.

Would adoption of the Staff's recommendations change this?

A. If the Commission adopts Staff's recommendations, it would do so only after consistent, thoughtful and high quality examination of key issues. Staff has provided information necessary for the Commission to change the sharing mechanism so that 85% of the increase is billed to and 85% of decreases in net fuel costs are returned to Ameren Missouri's customers and 15% of the increases in net fuel cost are absorbed, and 15% of decreases in net fuel costs are retained, by Ameren Missouri.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.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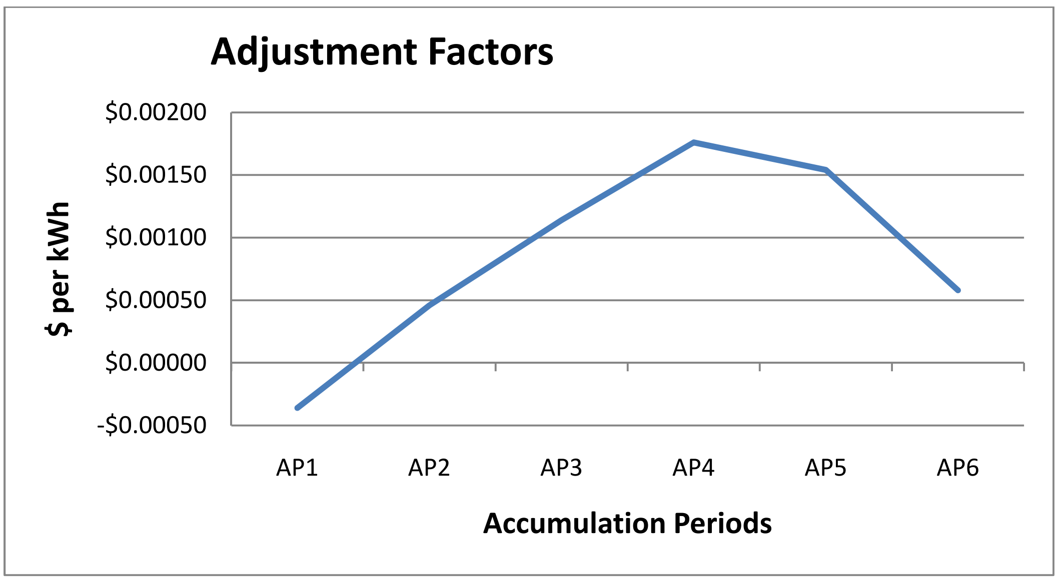
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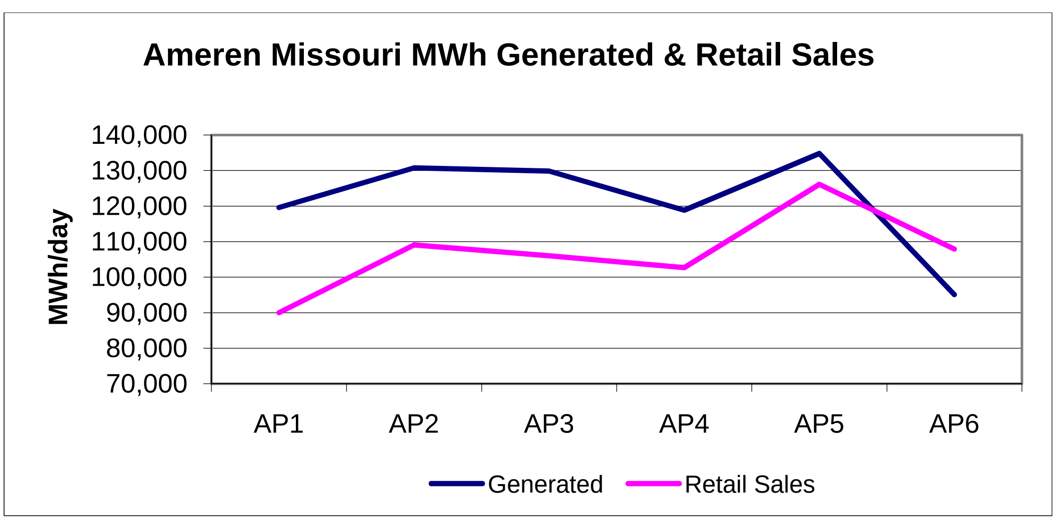
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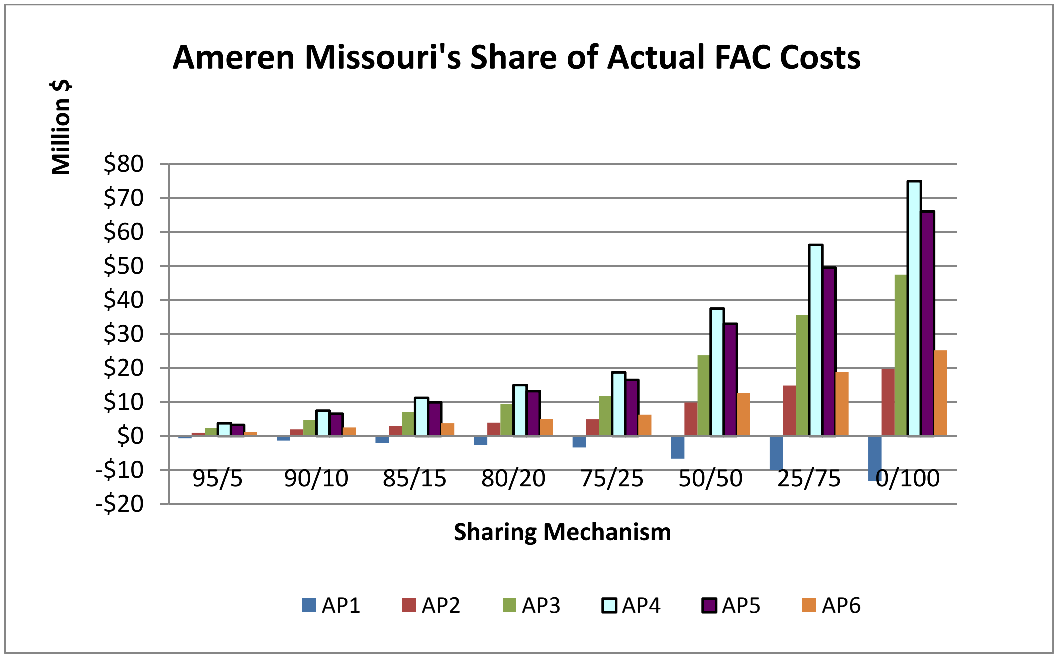
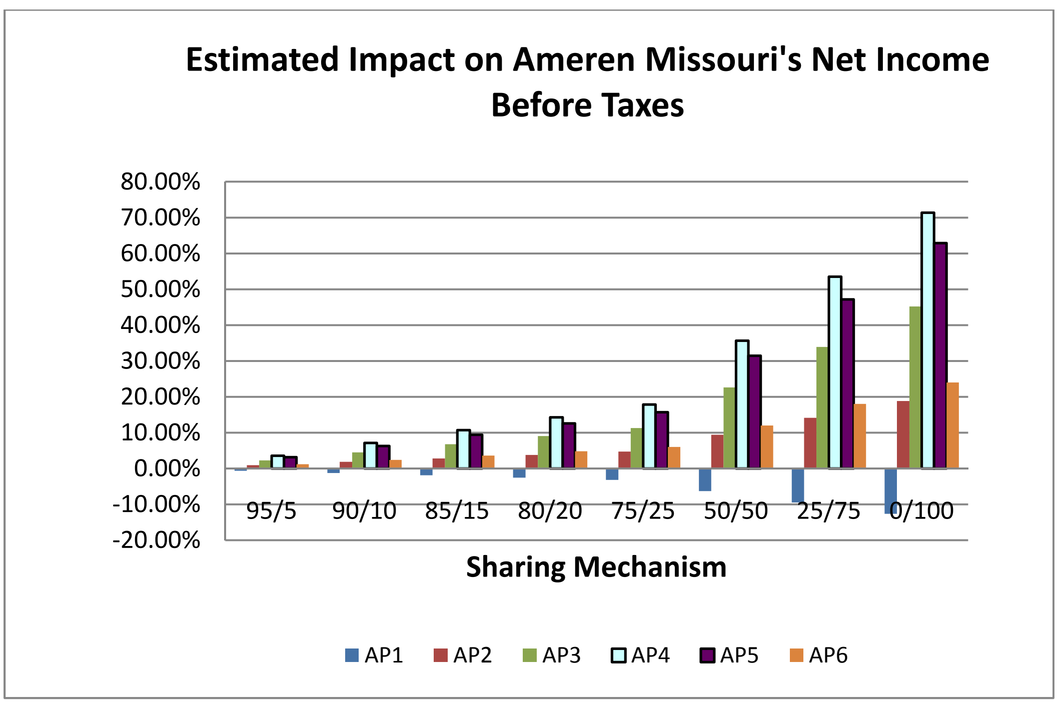
AP2
AP3
AP4
AP5
AP6
Generated
Retail Sales


Ameren Missouri's Share of Actual FAC Costs
Million $
$80
$70
$60
$50
$40
$30
$20
$10
$0
-$10
-$20
95/5
90/10
85/15
80/20
75/25
50/50
25/75
0/100
Sharing Mechanism
AP1
AP2
AP3
AP4
AP5
AP6


Estimated Impact on Ameren Missouri's Net Income Before Taxes
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
95/5
90/10
85/15
80/20
75/25
50/50
25/75
0/100
Sharing Mechanism
AP1
AP2
AP3
AP4
AP5
AP6

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO IMPLEMENT AN ENERGY COST ADJUSTMENT MECHANISM	))))	Docket No. 20000-368-EA-10 (Record No. 12477)

APPEARANCES

For the Applicant, Rocky Mountain Power (RMP or the Company):
PAUL J. HICKEY & O'KELLEY H. PEARSON, Hickey & Evans, LLP, Cheyenne, Wyoming; and YVONNE R. HOGLE, Senior Counsel, Rocky Mountain Power, Salt Lake City, Utah.

For Intervenor Office of Consumer Advocate (OCA):
IVAN H. WILLIAMS, Senior Counsel, Cheyenne, Wyoming.

For Intervenor Wyoming Industrial Energy Consumers (WIEC):
ROBERT M. POMEROY, JR., and THORVALD A. NELSON, Holland & Hart LLP, Greenwood Village, Colorado.

HEARD BEFORE
Chairman ALAN B. MINIER
Deputy Chairman STEVE OXLEY
Commissioner KATHLEEN A. LEWIS

STEVE MINK, Assistant Secretary,
Presiding pursuant to a *Special Order* of the Commission

MEMORANDUM OPINION, FINDINGS AND ORDER
(Issued February 4, 2011)

This matter is before the Wyoming Public Service Commission (Commission) upon the application of RMP for authority to implement an Energy Cost Adjustment Mechanism (ECAM) and the interventions of the OCA and WIEC. The Commission, having reviewed the application and attached exhibits, the evidence of record, its files concerning RMP, and applicable Wyoming utility law, and being otherwise fully advised in the premises, FINDS AND CONCLUDES:

Findings of Fact: Parties and Procedure

1. On April 5, 2010, RMP submitted an application, together with exhibits and revised tariff sheets, requesting authority to implement an ECAM to replace the existing Power Cost Adjustment Mechanism (PCAM) which sunset on November 30, 2010. The final PCAM rate effective period begins April 1, 2011, and ends March 31, 2012. RMP stated that the replacement for the PCAM, as opposed to elimination without replacement, is critical if it is to

have a reasonable opportunity to recover prudently incurred net power costs directly related to serving Wyoming customers.

2. The proposed ECAM would allow RMP to account for and collect or credit the differences between actual net power costs and a base level of net power costs established in either a general rate case or an ECAM case. RMP stated that it would compare the actual system net power costs to the base net power costs in rates on a monthly basis, and defer the differences in the ECAM balancing account.

3. RMP proposed to modify the dates used for the current PCAM to simplify ECAM preparation and review. Thus, it proposed to file an annual ECAM application on or before March 15 of each year, the same to be effective the following June 1. RMP also proposed that the ECAM be computed on a per-unit (dollars/MWh) basis, stating this would simplify the calculations and eliminate the complex allocation mechanism in the current PCAM. RMP stated that a per-unit calculation also accounted for fluctuations in volume to account for actual experience. In addition, RMP proposed the monthly interest on the net balance in the ECAM account be symmetrical as with the current PCAM. RMP proposed to include sulfur dioxide (SO_2) and renewable energy credit (REC) sales revenues in the ECAM to ensure the customer and RMP are fairly treated with respect to revenues from these sales. RMP also proposed that the ECAM not continue the dead band or the three sharing bands from the PCAM, and instead proposed that the ECAM include a single 95%/5% sharing band. Finally, RMP proposed to change the historical test period for consideration of deferred net power costs in the first ECAM to include deferred net power costs from December 1, 2010, through December 31, 2011.

4. On April 5, 2010, the Commission issued its *Suspension Order* suspending the proposed rates for investigation and further action for the initial six-month period provided in W.S. § 37-3-106(c) which commences after the 30-day notice term provided in subsection (b) thereof. On that day, RMP filed a Petition for Confidential Treatment and Protective Order (*Petition*).

5. On April 7, 2010, the Commission issued a *Notice of Application* with a protest deadline date of May 7, 2010, which was published once per week for two consecutive weeks in the *Glenrock Independent*, the Thermopolis *Independent Record*, the *Casper Star-Tribune*, the *Riverton Ranger*, the *Northern Wyoming Daily News* in Worland, the *Daily Rocket-Miner* in Rock Springs, the *Pinedale Roundup*, the *Uinta County Herald* in Evanston, the *Cody Enterprise*, the *Buffalo Bulletin*, the *Douglas Budget*, the *Lovell Chronicle*, the *Green River Star*, the *Lander Journal*, and the *Daily Boomerang* in Laramie. A public service announcement with regard to the application was broadcast on radio five times per week for two consecutive weeks on *KTWO* in Casper, *KLDI* in Laramie, KTRZ in Riverton, *KRKK* in Rock Springs, *KKTY* in Douglas, *KOVE* in Lander, *KBBS* in Buffalo, *KEVA* in Evanston, *KTHE* in Thermopolis, *KWOR-AM* in Worland, *KPIN* in Pinedale, *KMER* in Kemmerer, and *KODI* in Cody.

6. On April 8, 2010, OCA filed its *Notice of Intervention*. OCA thereupon became a party to this proceeding for all purposes. On this date, Paul Hickey of Hickey and Evans, LLP filed an *Entry of Appearance* for RMP.

7. Pursuant to open meeting action taken on April 15, 2010, the Commission issued a *Protective Order* on April 16, 2010.

8. On April 27, 2010, WIEC filed its *Petition for Leave to Intervene* and its *Motion for Admission Pro Hac Vice of Robert M. Pomeroy, Jr., and Thorvald A. Nelson (Motion)***.** The Commission issued an *Order* granting the *Motion* on May 24, 2010, and *Order Authorizing Intervention* granting WIEC's petition to intervene, whereupon it became a party for all purposes to this proceeding.

9. On May 24, 2010, the Commission issued a *Notice Setting Scheduling Conference*, setting a scheduling conference for May 27, 2010, at the Commission's offices.

10. WIEC filed the following *Nondisclosure Agreements*: Thorvald A. Nelson, Magdalena Ackenhausen, Michael Gorman, Randall Falkenberg and Lauren Falkenberg (June 11, 2010); Mark Widmer (June 16, 2010); and Neal Townsend, Kevin Higgins, Oliwia Smith, Kelly Francone and Robert M. Pomeroy (July 6, 2010).

11. On May 27, 2010, the Commission held a scheduling conference and issued its *Scheduling Conference Order* on July 30, 2010, which set the following procedural schedule agreed upon by the Parties at the scheduling conference:

All parties to complete discovery on RMP's pre-filed direct testimony and application (all responses due within 10 business days)	August 27, 2010
All Intervenors to pre-file direct testimony (responses to discovery due within 7 business days)	September 10, 2010
RMP rebuttal testimony and Intervenor cross-answer testimony	October 15, 2010
All Parties to complete discovery on RMP's rebuttal testimony	October 29, 2010
Pre-hearing conference	November 5, 2010, 9:00 a.m.
Exhibit conference	November 8, 2010, 8:30 a.m.
Public Hearing	November 8-10, 2010, 9:00 a.m.

12. On September 10, 2010, WIEC filed the direct testimony and exhibits of Kevin Higgins, Michael Gorman and Randall J. Falkenberg. The filing contained confidential information. On that date, OCA filed the prefiled direct testimony and exhibits of Denise Kay Parrish. On October 15, 2010, OCA filed Parrish's cross-answer testimony.

13. On October 18, 2010, RMP filed rebuttal testimony and exhibits of Gregory N. Duvall, Stefan A. Bird, Karl A. McDermott; and, Samuel C. Hadaway.

14. On October 22, 2010, the Commission issued a *Procedural Notice and Order Setting Hearing*, setting a public hearing to commence on November 8, 2010. The *Notice* was published once per week for two consecutive weeks in the *Glenrock Independent*, the Thermopolis *Independent Record*, the *Casper Star-Tribune*, the *Riverton Ranger*, the *Northern Wyoming Daily News* in Worland, the *Daily Rocket-Miner* in Rock Springs, the *Pinedale Roundup*, the *Uinta County Herald* in Evanston, the *Cody Enterprise*, the *Buffalo Bulletin*, the

Douglas Budget, the *Lovell Chronicle*, the *Green River Star*, the *Lander Journal*, and the *Daily Boomerang* in Laramie. A public service announcement with regard to the application was broadcast on radio five times per week for two consecutive weeks on *KTWO* in Casper, *KLDI* in Laramie, KTRZ in Riverton, *KRKK* in Rock Springs, *KKTY* in Douglas, *KOVE* in Lander, *KBBS* in Buffalo, *KEVA* in Evanston, *KTHE* in Thermopolis, *KWOR-AM* in Worland, *KPIN* in Pinedale, *KMER* in Kemmerer, and *KODI* in Cody.

15. On November 3, 2010, the Commission issued its *Suspension Order* suspending the proposed rates in this case for the final three month period allowed by W.S. § 37-3-106(c).

16. On November 4, 2010, O'Kelley H. Pearson filed an *Entry of Appearance* on behalf of RMP. On this date, the parties filed a *Stipulated Summary of Uncontroverted Facts*. RMP filed its [i] *Summary of Contentions;* [ii] *Schedule of Exhibits;* [iii] *Summary of Issues of Fact and Law for Determination by the Commission;* and [iv] *Notice of Filing Pre-Hearing Conference Submission Pursuant to the Commission's July 30, 2010, Scheduling Conference Order.*

17. On November 5, 2010, OCA filed its [i] *Updated Summary of Contentions;* [ii] *Summary of Remaining Issues of Fact and Law for Determination by the Commission;* and [iii] *Revised Schedule of Exhibits.* WIEC filed its [i] *Designation of Wyoming Industrial Energy Consumers Exhibits*; [ii] *Summary of Issues of Fact and Law*; [iii] *Summary of Contentions*, and [iv] *Corrected Designation of Wyoming Industrial Energy Consumers Exhibits*.

18. On November 8, 2010, and pursuant to W.S. §§ 37-2-102 and 16-3-112, the Commission issued its *Special Order Authorizing One Commissioner and/or Hearing Examiner to Conduct Public Hearing.*

19. Pursuant to the Commission's orders and due notice, the public hearing in this matter was held on November 8-10, 2010, in the Commission's hearing room in Cheyenne. RMP, OCA and WIEC appeared and participated fully in the hearing. RMP presented its case through witnesses Gregory N. Duvall, Bruce N. Williams, Karl A. McDermott, Samuel C. Hadaway, and Stefan A. Bird. The OCA presented its case through its witness Denise Kay Parrish. WIEC presented its case through its witnesses Michael Gorman, Kevin C. Higgins and Randall J. Falkenberg. During the hearing, the Commission took judicial notice of its *Order Approving Stipulation* issued on March 24, 2006, in Docket No. 20000-230-ER-05 (Sub 230). (Transcript of public hearing proceedings, hereinafter, Tr., Vol. II, p. 295.) At the conclusion of the public hearing, the parties waived closing arguments and agreed to file briefs by December 20, 2010. The Commission thereupon closed the record.

20. On December 21, 2010, RMP, OCA and WIEC filed their respective *Post-Hearing Briefs.*

21. Pursuant to W.S. § 16-4-403, the Commission held public deliberations on January 5, 2011, and directed the preparation of an order consistent with its determinations.

Findings of Fact: Party Positions

RMP

22. Gregory Duvall, Director of Long Range Planning and Net Power Costs for RMP, provided an overview of the proposed ECAM, terming the proposed ECAM a cost recovery mechanism, differentiating it from the current PCAM which he characterized as a safety net mechanism. (Tr., Vol. I, pp. 33, 156.) Duvall characterized the proposed ECAM as a means to mitigate forecasting risk. (Tr., Vol. I, pp. 133-134.) He stated the current PCAM was no longer adequate to capture prudently incurred net power costs and had resulted in the under-recovery of $25 million in net power costs from Wyoming. He argued that, if the PCAM had been in effect in all six states, the total under-recovery would have been $225 million on a company-wide basis. Duvall believed the under-recovery was driven by the dead band and sharing bands included in the current PCAM. (Tr., Vol. I, p. 34.) He noted the proposed ECAM does not include either a dead band or the three sharing bands found in the current PCAM. Rather, the proposed ECAM will include a single sharing 95%/5% sharing band, under which customers would pay or receive 95% of the difference between actual and base net power costs; and RMP would pay or receive 5% of the difference between actual and base net power costs. Duvall stated the proposed ECAM is based on an annual true-up of forecast net power costs to actual net power costs based on a 12 month year ending December 31 of each year, with a filing on March 15 each year and a rate effective date of the following June 1. The company proposed that the first ECAM include December 2010 in the balance because it would not be covered under the PCAM which expired on November 30, 2010. (Tr., Vol. I, pp. 33-35, 155.)

23. Duvall stated the proposed ECAM will include renewable energy credit (REC) and sulfur dioxide (SO_2) revenues in addition to net power costs along with the embedded cost differential (ECD) adjustment that is part of the current PCAM. He stated the ECAM balances would continue to be recovered and returned to customer though RMP's existing Schedule 95 tariff. Duvall did not recommend that the true-up mechanism be removed altogether, explaining his opinion that its removal was not a viable option since the $25 million dollar under-recovery experienced under the current PCAM would persist. (Tr., Vol. I, pp. 33-35, 101-102, 114-115.)

24. Duvall also addressed market volatility and the historical fluctuations of electricity prices, stating that, from January 2005 through December 2009, prices ranged from zero to $300 per megawatt hour (MWh). He also discussed the Company's acquisition of additional resources such as 2500 megawatts (MW) of natural gas generation and 1750 MW of wind generation to reduce its reliance on coal-fired generation from 60% to 30%. Duvall stated market volatility and RMP's acquisition of additional resources have caused net power costs to become more volatile and unpredictable. Duvall explained that production cost models, such as RMP's GRID model, are not able to capture these volatilities since they are based on a static view of the world. Duvall did not believe RMP could eliminate risk and volatility using hedging instruments. He stated the Company is able to hedge certain future natural gas requirements in wholesale transactions (the context of the GRID model); but significant variations in the Company's net open position occur through the actual period as a result of substantial uncontrollable and unpredictable volatility in loads and resources that occur simultaneously with substantial uncontrollable and unpredictable volatility in prices of natural gas and electricity.

Duvall stated RMP does not believe that fixing the GRID model could address "the realities of the actual world. The only reasonable solution is the company's proposed ECAM." (Tr., Vol. I, pp. 35-36.)

25. Duvall discussed the stochastic analysis he performed to quantify the possible effect of model-simulated actual conditions which differ from the assumed static conditions characteristic of the GRID model. In the study, Duvall used the Company's Planning and Risk model to derive the portfolio stochastic cost utilizing 100 Monte Carlo simulation outcomes for the study year, 2012. In one model run, the loads, forced outages and hydro generation were not subject to the 100 Monte Carlo simulations, producing a model run that simulated the case where the Company fully and perfectly hedges its risk associated with these variables. In another model run, these variables were subject to the random draws of the Monte Carlo simulation. (RMP Exhibit 1, pp. 16-17) The comparison between the two model runs indicates the volatility of loads, hydro and forced outages increased the portfolio stochastic costs by $80 million per year. He noted his analysis did not account for the variability of wind which he claimed would add another six to ten dollars per MWh to power costs. (Tr., Vol. I, pp. 36-37.)

26. In rebuttal, Duvall discussed the proposals by WIEC witness Falkenberg and OCA witness Parrish. He stated both proposals ignore the historical under-recovery of net power costs; and both proposals increase the under-recovery of net power costs. Duvall stated that Falkenberg's proposal to double the dead band and sharing bands would increase the under-recovery in the historical PCAM from $25 million to $43 million on a Wyoming-specific basis and by $225 to $339 million on a total company basis. He stated that Parrish's proposal to eliminate the dead band and sharing bands and set net power costs at 90% of forecast or lower is unreasonable and does not address the historical under-recovery of net power costs. Regarding Falkenberg's claim that the under-recovery of net power costs could have been reduced if RMP had set the net power costs in rates at higher levels, Duvall said that RMP cannot set its own rates. Regarding Falkenberg's proposal that RMP should forecast net power costs for the rate effective periods, Duvall argued the suggestion was irrelevant and had never been advocated by WIEC in the past. Duvall noted that, while this method (the "Oregon method") uses forecasting, it is still a static view of the future and fails to address the volatile and changing conditions the Company faces in serving customer loads. Duvall termed Falkenberg's idea that RMP should replace its dollar per MWh proposal with an average of the system generation and system energy allocation factors was simply unreasonable. (Tr., Vol. I, pp. 37-38)

27. In summary, Duvall stated that the proposed ECAM is "a simple straightforward and transparent mechanism designed to fulfill the regulatory compact borne out of the obligation to serve, of providing reliable and low-cost service to customers in return for the company recovering its prudently incurred net power costs." He recommended the Commission approve the application. (Tr., Vol. I, p. 38.)

28. WIEC questioned Duvall on the history of the PCAM and his understanding of Commission Rules 249 and 250. Duvall acknowledged these Rules allow utilities a dollar-for-dollar recovery of certain prudently incurred commodity and commodity-related costs; but Duvall believed the proposed ECAM falls under W.S. § 37-2-121 as innovative or nontraditional rate making. (Tr., Vol. I, p. 156.) He stated the PCAM was the result of the 2001 Western

Energy Crisis and was established as a safety net mechanism. (Tr., Vol. I, pp. 40-41.) He acknowledged the current PCAM was consistent with the settlement agreement between RMP, WIEC, OCA and the other parties in the Sub 230 case in which the Commission approved the PCAM pursuant to its authority under W.S. § 37-2-121 rather than Rules 249 and 250. (Tr., Vol. I, p. 42.) He stated that he did not know whether the costs proposed to be recovered under the ECAM, which are the same as the costs recovered under the current PCAM, are eligible for recovery under Commission Rules 249 and 250. His understanding was that, in Sub 230, PacifiCorp understood that the PCAM, as it agreed to in the settlement, would not provide a direct pass-through of costs. He noted that the PCAM involved a sharing of the risk of cost increases between PacifiCorp and its customers and was not intended as a mechanism to pass net power costs through to customers. (Tr., Vol. I, pp. 42-43.)

29. Responding to WIEC, Duvall agreed that RMP could file a rate case if it were concerned that it was not earning its authorized rate of return. He acknowledged that RMP has filed numerous rate cases since the current PCAM went into effect and that each was settled between itself, WIEC and the OCA whereby the Company agreed to a smaller rate increase than it originally requested. He agreed that each of these settlements included agreements to levels of base net power costs in rates which were lower than the levels RMP initially proposed. He acknowledged the Company supported each settlement as serving the public interest, and if the Commission had accepted RMP's filed levels of base net power costs rather than the amounts settled upon, it would have experienced higher revenues in the 2006-2009 period. Duvall explained that RMP's calculation of the net power cost under-recoveries during 2006-2009 differed from WIEC's calculation because witness Falkenberg used six more months of data than RMP. (Falkenberg Testimony, p. 17, Table 1; and Tr., Vol. I, pp. 45-48, 50-52.)

30. Duvall agreed that hedging can decrease the price volatility of RMP's natural gas purchases for electric generation for a given point in time and a given open position. Duvall stated the company hedges natural gas supplies for its electric operations in addition to owning and operating coal mines to maintain some control over the effects of coal price variations. He agreed that long-term contracts mitigate price risk when contrasted to reliance on spot market purchases. (Tr., Vol. I, pp. 52-55.) Duvall agreed that the Company's capacity derived from hydroelectric generation has decreased as a percentage of its total portfolio. He stated that on a MWh basis, hydroelectric capacity has decreased because of some expiring contracts, although company-owned hydro had remained fairly constant. (Tr., Vol. I, p. 55.) Duvall stated that the portion of RMP's total capacity derived from wind generation resources, which have no associated fuel cost, has increased over time and is expected to continue to increase. He further agreed that natural gas fired generation capacity has increased over time, noting that replacing coal plants with natural gas plants will increase the impact of natural gas costs in the ECAM. (Tr., Vol. I, pp. 56, 88-89.) Duvall acknowledged that proper inspection and maintenance of the Company's system might reduce the number of forced outages and the associated price volatility, but the Company cannot control the timing of those outages. (Tr., Vol. I, p. 57.)

31. Duvall noted that, after filing the instant application, RMP filed an application in Docket No. 20000-381-EA-10 (Sub 381) for approval of revisions to the interjurisdictional allocation methodology. Duvall stated that RMP intends to use the approved allocation methodology from Sub 381 for purposes of the ECAM, assuming that the Commission approves

the Sub 381 application and some form of an ECAM, including base net power costs. He stated it would not make sense to apply the average of the system energy (SE) and the system generation (SG) factors, as proposed by WIEC witness Falkenberg, since most of the net power cost is allocated on the system energy factor. (Tr., Vol. I, pp. 58-60.) When asked if RMP objected to using the allocation method approved in Sub 381 for the purposes of calculating both base net power costs and actual net power costs for the purposes of the ECAM, Duvall responded:

> I think the point of the company's dollar per megawatt-hour approach is it's very simple and, I believe comes out with – I think if you could try to figure out how to allocate your base net power costs and your actual net power costs using the SE and SG factors and then too those on a dollar per megawatt-hour basis to do the same sort of calculation that we've done in our ECAM, I can't imagine that it would be significantly different. (Tr., Vol., I, p. 60.)

Duvall later clarified that the Company's proposal is not a request to abandon the current interjurisdictional allocation methodology. He stated the Company uses the current methodology for setting base net power costs and that the dollar per megawatt-hour method is only for the incremental piece in the ECAM. (Rocky Mountain Power Exhibit 11; Tr., Vol. I, pp. 149-152.)

32. Duvall stated that allocating base net power costs using one methodology and thereafter employing a different methodology to allocate actual net power costs for the true-up would make the calculation simpler. He stated that people have complained that the current method is too complex; and the proposed methodology is intended to simplify a very complex methodology. He agreed that theoretically, if different methods were used to allocate base net power costs and actual net power costs, the resulting answers could be different. (Tr., Vol. I, pp. 60- 63.)

> And so if your dollar per megawatt-hour of your base and your dollar per megawatt-hour of your actual are different, that's what we're measuring in this calculation. So we're not actually allocating the actuals. (Tr., Vol. I, p. 64.)

33. Regarding the impact to the embedded cost differential, should the Sub 381 application be approved, Duvall testified that the 2010 Revised Protocol eliminates qualifying facilities from the calculation. (Tr., Vol. I, p 69.) Duvall testified that the Company proposes to forecast net power costs to establish the level of base net power costs for use in the ECAM. When asked what time period would the Company propose its forecast to begin and end, Duvall stated the Company proposes that it be allowed flexibility to file whatever forecast it believed was appropriate in any application it files before this Commission to set base net power costs. Duvall stated that he would not object to WIEC witness Falkenberg's suggestion to use a forecast that starts the first day of the rate-effective period. Duvall stated he calls this forecast method the Oregon method. (Tr., Vol. I, pp. 69-71)

34. Duvall testified that, in the past, RMP has relied on the GRID model to forecast proposed rates in Wyoming. He explained RMP's position in this case is that GRID is a static model that does not take into account all the volatility that can occur after the model's static view

is in place. He stated that RMP may address some modeling issues, and, if rates are still set based on models, RMP will probably try to address the static versus real world issue. He stated that RMP is examining other models but believes no model can take into account the changes in load, hydro, wind and other variables. Duvall believed that stochastic models best account for variability because they include random variability in hydro, loads and the timing of thermal unit forced outages. He agreed that WIEC and OCA have accepted the use of forecast test periods to set base net power costs. (Tr., Vol. I, pp. 70-73, 89-90, 103-105.) Duvall agreed that, under the proposals of RMP, WIEC and OCA, whether net power costs are increasing or decreasing in absolute terms matters much less than whether or not net power costs turn out to be higher or lower than the forecasted level. (Tr., Vol. I, pp. 73-80.) Duvall characterized the ECAM as a means to mitigate forecast risk; i.e., the risk the Company claims the GRID model introduces by failing to adequately forecast increases in costs. Duvall asserted that costs have been consistently underforecasted, noting that RMP has recently experienced shortfalls in the range of 3-8% annually. (Tr., Vol. I, p. 134, 152-155.)

35. Duvall discussed WIEC's claim that the Energy Gateway transmission project Gateway Project (Gateway) will dampen net power cost volatility. He stated that Gateway will improve transmission reliability on the PacifiCorp system by allowing RMP to more efficiently meet the load and resource needs on its system. This means that RMP would have a wider range of options for efficiently dispatching resources to meet load. Duvall stated enhancing system transfer capability allows the Company to address volatility more efficiently. (Tr., Vol. I, pp. 80-82, 134-136.)

36. Duvall discussed other PacifiCorp jurisdictions that have mechanisms similar to the proposed ECAM and how the various mechanisms differ. RMP has a proposed ECAM in Utah that is fairly similar to the Wyoming proposal. He stated the mechanism now in place in Idaho is similar to Wyoming's and has a 90/10 sharing band with no dead band. (RMP Exhibit 9.) A California mechanism has no sharing or dead bands; and no ECAMs are in place in Oregon or Washington. (Tr., Vol. I, pp. 85-86.) Regarding sales for resale, he was not aware of PacifiCorp ECAMs that dealt with them. Duvall stated the Company purchases power as necessary to meet its requirements and does not separate out sales for resale. (Tr., Vol. I, p. 85.) When asked why wheeling revenues were not included in RMP's Account No. 456, Other Electric Revenues, Duvall stated wheeling had traditionally not been included in net power costs. He stated wheeling expense and wheeling revenues have different purposes. Duvall explained that wheeling expenses are incurred to move power to serve RMP's customer loads and wheeling revenues are received from other parties using RMP's transmission to serve their loads. He stated that, if you look at net power costs as costs needed to serve the Company's load, wheeling expenses, and not wheeling revenues, would be included in the Account 456. He stated credits for wheeling revenue are fixed in the rates and are not included in the PCAM or proposed ECAM. He stated, however, that RMP would not oppose the inclusion of wheeling revenues in the Wyoming ECAM. (Tr., Vol. I, pp. 85-86, 100-101.)

37. Duvall stated the availability of gas storage is limited and has not been directly addressed in the Company's IRP. (Tr., Vol. I, p. 91.) He noted that the IRP balances the increased volatility of net power costs caused by the increase in wind production and flexible natural gas generation resources. (Tr., Vol. I, pp. 91-92.) Duvall described the limited control

RMP has over its net power costs, noting they are volatile, difficult to predict and many elements are not subject to its control. (Tr., Vol., I, p. 93.) Duvall was of the opinion that tightening up dead bands rather than improving the Company's forecasts would be a more viable option given [i] how difficult it is to forecast net power costs and [ii] the differences between models and what actually occurs. Duvall stated eliminating the dead band and shrinking the sharing band would allow the recovery of actual net power costs to be more in line with forecasts. He stated that, while forecasts within models can be improved, the real world operations of the Company cannot be simulated. Duvall stated the Company looks for ways to improve the forecasts, commenting that ". . . if you forecast for the in-rates period, you get a different answer than if you forecast for something that occurs prior to the in-rates period." (Tr. Vol. I, pp. 93-95, quote at 95.)

38. Duvall stated RMP would prefer to have a full true-up with no sharing bands. The proposed ECAM eliminates the dead band altogether but proposes a single sharing band with 95% of the prudently incurred costs to be borne by ratepayers, and the balance to be borne by the Company. Duvall acknowledged that the Company offered no derivation for its proposed 95/5 sharing percentages. (Tr., Vol. I, p. 95.) Duvall stated the Company reviewed its mechanisms in other states to determine what it would propose for the sharing band in Wyoming. He stated the 90/10 sharing band utilized in Idaho was the result of a negotiated settlement. He believed the Idaho Commission had since changed that to a 95/5 sharing band. (Tr., Vol. I, pp. 95-96.)

39. Duvall, acknowledged that the ECAM Stipulation in Idaho does not include RECs, but it included RECs in its Idaho general rate case. (Tr., Vol. I, pp. 110-113.) According to Duvall, the Idaho ECAM includes wheeling expenses but not revenues, stating wheeling expenses are components of net power costs. RMP offered the Idaho Commission's March 31, 2010, Order in which it accepted an ECAM that included wheeling expenses. (Tr., Vol. I, pp. 148-149; Rocky Mountain Power Exhibit 12.) Duvall acknowledged there is not a lot of volatility in the unit cost of wheeling, noting that it obtains wheeling primarily from Bonneville Power Administration and Idaho Power Company. (Tr., Vol. I, pp. 123-125.)

40. Duvall said there would be the need for a true-up if the Commission did not approve the Company's dollar per MWh methodology, noting that the current mechanism includes a true-up provision. (Tr., Vol. I, pp. 96-97, 120.) When asked why the Company was proposing a change in methodology without calculating the impact, Duvall stated the proposed methodology deals with the difference between actual and forecast net power costs. He stated RMP was not proposing to change the allocation of the base net power costs. (Tr., Vol. I, pp. 97-98.) When asked what effect removing the embedded cost differential would have on rates in Wyoming, Duvall said the rate impact would be on a going forward basis and would depend on the components of the embedded cost differential. (Tr., Vol. I, pp. 98-99.) Duvall thought WIEC witness Falkenberg's suggestion to include a true-up of PCAM revenues and recoveries in the proposed ECAM was reasonable. (Tr., Vol. I, pp. 99-100, 162.)

41. Duvall said RMP intends to file rate cases annually through 2014 and RMP would also file separate ECAM applications annually rather than including them in rate cases as there were no plans to file them together. (Tr., Vol. I, pp. 113-114.) Duvall believed general rate cases are unsatisfactory vehicles for the full recovery of net power costs stating that it would be

nearly impossible to establish a “normalized” level of net power costs in a rate case that would accurately reflect actual future events given their volatility. He indicated that the component parts of net power costs have not changed over time. (Duvall Direct Testimony, p. 10; Tr., Vol. I, pp. 117-119.)

42. Duvall said it was impossible for RMP to effectively hedge its actual load and resource balance one year in advance. (Duvall Direct Testimony, pp 14-17; Tr., Vol. I, pp. 121-122.) He testified that on-system wholesale sales revenues are not included in RMP’s Account 447, Sales for Resale. Because on-system wholesale sales are under the FERC’s jurisdiction, the Company removed the allocation factor calculation. On-system wholesale sales revenues “. . . are not passed back through retail rates because they’re their own FERC jurisdiction. So they get a full allocation of all of the embedded costs.” According to Duvall, retail ratepayers benefit from wholesale sales on the system through lower allocation factors. Regarding off-system wholesale sales, Duvall stated that they are fully included in net power costs as revenue credits. He stated the contracts are under the FERC jurisdiction but the sales are not. (Tr., Vol. I, p. 125-130.)

43. Duvall argued that RMP should recover 100% of its prudently incurred costs from ratepayers. (Tr., Vol. I, p. 144.) However, he acknowledged customers have no control over net power costs or how the Company manages them. He stated customers generally do have control over what load they place on the system. (Tr., Vol. I, p. 145.)

44. Duvall explained how REC revenues were accounted for in Docket No. 20000-352-ER-09 (Sub 352), RMP’s previous rate case, and proposed those revenues be shared 95/5 in the proposed ECAM. (Tr., Vol. I, pp. 138-139.) He explained that this proposed sharing treatment of REC revenues would give RMP an incentive to maximize REC revenues. No incentive existed in the Sub 352 rate case because REC revenues were applied as an offset against the revenue requirement. (Tr., Vol. I, pp. 146-147.)

45. Bruce Williams, PacifiCorp’s Vice President and Treasurer, supported the application and testified about transitioning from the sunsetting of the current PCAM to the proposed ECAM. (RMP Exhibit 3.) He discussed how the loss of a fuel and purchased power adjustment mechanism increases the risks to earnings and cash flow caused by the volatility inherent in net power costs. He stated this volatility can adversely impact the Company’s access to capital and liquidity to the detriment of the Company and its customers. Williams discussed RMP’s capital needs, stating it was in the midst of a major building cycle to address increasing load growth in Wyoming. According to Williams, RMP’s capital budget exceeds cash from operations. Williams acknowledged, however, that the Company has experienced positive returns from its Wyoming operations; and RMP’s total revenues from Wyoming each year exceed its total expenses assigned to Wyoming each year. (Tr., Vol. pp. 185-186.)

46. Williams stated the Company will need continued access to additional capital in order to fund its capital program. Therefore, credit ratings have been, and will continue to be, important to its ability to access capital markets on reasonable terms. Williams discussed the factors ratings agencies such as Standard and Poor’s (S&P) use when determining a utility’s credit rating. In the regulatory environment, Williams noted, rating agencies frequently look at

the absence or existence of a purchased power and fuel adjustment mechanism such as the proposed ECAM when determining a credit rating. Williams noted that an S&P credit report viewed Wyoming's PCAM (which included the sharing bands and dead bands) as a positive influence on the Company's credit while listing the absence of fuel and purchased power adjustment mechanisms for the Company in Utah, Washington and Idaho as material weaknesses under the major rating factors. Williams agreed that while the structure of the proposed mechanism decreases the risk to the Company and is viewed favorably by credit rating agencies, it may not increase the Company's credit rating. Williams stated that he believed the ECAM would help RMP's credit metrics, especially cash flow metrics, thereby allowing for a better recovery of those costs which would improve the Company's ratios. (Tr., Vol. I, pp. 180-182, 189-190, 200.) Williams discussed that rating agencies factor into credit ratings the institution of mechanisms such as the proposed PCAM as regulatory support. He stated Moody's reviews four principal criteria: [i] regulatory environment; [ii] ability to recover costs and expenses; [iii] diversification; and [iv] financial strength and liquidity. (Tr., Vol. I, 191-192.)

47. Williams stated the benefits the proposed ECAM would provide include such things as [i] moderating the amount of imputed debt and interest expense adjustments related to power purchase agreements S&P makes to the Company's published financial results when determining adjusted credit metrics, and [ii] reducing the amount of back-up credit required to ensure the Company can continue to fund operations in the event of constrained liquidity conditions. (Tr., Vol. I, pp. 182-184, 186-189.)

48. Karl A. McDermott, PhD, Ameren Distinguished Professor of Business and Government at the University of Illinois, Springfield, and special consultant to National Economic Research Associates, Inc., testified on ECAM-like rate making mechanisms and RMP's proposed ECAM, in part through his prefiled direct and rebuttal testimony. (RMP Exhibits 4, 5.) McDermott presented data confirming the volatility of net power costs relative to non-net power costs. He discussed the reasons net power costs are more volatile than non-net power costs stating the vast majority of net power costs are incurred to ensure the system balance is maintained in order to preserve the safety, adequacy and reliability of power supplied to customers. McDermott stated that net power costs vary by two to two and a half times more than non-net power costs. McDermott stated that dead and sharing bands were not necessary "to discipline the company" because the proposed ECAM provides a balancing mechanism that flows costs through to customers, allows for a prudency review, and provides the possibility of refund. He stated that "[t]he vast majority of other state commissions have recognized this as well and rely primarily on the prudence review process to provide incentives to companies to control their costs." (Tr., Vol. I, pp. 214-216, 226-236, quote at p. 216.)

49. McDermott encouraged the Commission to follow other states' example and eliminate the dead bands and sharing band. However, for RMP, McDermott conceded that the Commission could properly consider the commercial disadvantage to Wyoming industry that might result because of RMP's high industrial load (70% of RMP's Wyoming load is industrial). Approximately $61.8 million has been paid out to the Company from customers under the current PCAM, of which, 70% was paid by industrial customers. (Tr., Vol. I, pp. 281-283.) According to McDermott, the Company, as well as its customers, benefit from removing the sharing band and dead bands in terms of preserving the cash flow the Company needs to meet

the varying costs of effectively balancing the system. McDermott stated that dead bands and sharing bands disallow a cost without the benefit of review which results in Wall Street putting companies under credit watches or other lists and may adversely impact the Company's ability to obtain capital at a reasonable cost. McDermott concluded his testimony stating that simplifying the ECAM design with a 95/5 sharing band would serve the public interest. He reemphasized his support for prudency reviews as powerful incentives for the Company to control net power costs. (Tr., Vol. pp. 216-218, 236-238, 241-249.)

50. Dr. Samuel C. Hadaway, a principal in FINANCO. Inc., of Austin, Texas, testified on behalf of RMP and in support of his prefiled rebuttal testimony (RMP Exhibit 7) in which he responded to WIEC witness Falkenberg's opinion that variations in rate of return estimates are indicative of "normal course of business" operating risks for electric utilities like RMP. (WIEC Exhibit No. 203, pp. 27-28.) Hadaway stated that Falkenberg tried to use data from Hadaway's rate-of-return estimation models to support a 100 basis point dead band in WIEC's proposed ECAM. Hadaway said this approach wrongly attempts to connect two totally unrelated issues. Hadaway stated variations in the results from the DCF or risk premium models have nothing to do with a utility's operating profits or fluctuations in utility's operating portfolios in the normal course of business. Hadaway argued that variations in the results of rate of return estimation models have nothing to do with a utility's earnings or cash flow. He stated that Falkenberg's 100 basis point dead band is four times larger than the 25 basis point range on either side of the mean (9.6% to 11.6%) he would normally recommend. (Tr., Vol. III, pp. 528-529.)

51. Stefan A. Bird, PacifiCorp Energy's Senior Vice President, Commercial and Trading, supported his rebuttal testimony (RMP Exhibit 6) and testified on other issues. He explained how the Commercial and Trading Group performs its job of balancing the Company's constantly changing loads and resources. He stated that a sharing or dead band would have no impact on the Commercial and Trading Group and their daily decisions on which generating units to ramp up, whether to buy or sell power, and what transmission needs to be scheduled. (Tr., Vol. III, pp. 542-546.)

52. Bird's rebuttal testimony addressed issues raised by the OCA and WIEC regarding hedging, forecast volume, dead and sharing bands and possible cost and revenue items where incentives could exist if appropriately designed. Bird stated that, for the ECAM to be just and reasonable, the mechanism must [i] reasonably allow the Company to recover all of the costs prudently incurred in serving customers, and [ii] provide the Company with a reasonable opportunity to earn it authorized ROE. Bird stated:

> To go beyond the Company's proposed 95/5 sharing band to a greater sharing band, then you must believe that the Company, first of all, has a base forecast with a 50/50 chance of being higher or lower and, secondly, that the Company has a reasonable ability to offset the uncontrollable factor with something else that's within its control; otherwise, your decision would be imposing a disallowance that is, in effect, simply a reduction of the authorized ROE.

Bird contended that WIEC's and OCA's proposals are ". . . well outside that reasonable range and well outside the mainstream." (Tr., Vol. III, pp. 547-548.)

53. Bird commented on the industry changes which caused the Company to seek the proposed ECAM. He explained that the volatility of the market and resources is greater today than ten or twenty years ago. Furthermore, RMP's resource portfolio has changed from predominantly depending on stable lower cost coal-fired resources to one characterized by a more diverse range of generation resources that includes, for example, wind generation which is very volatile. Bird discussed the influence on market price and cost volatility associated with 1500 MW of natural gas generation capacity and 1500 MW of owned and contracted wind generation capacity added over the past three years. According to Bird, the approach of setting rates on a forecast model is no longer viable. He also asserted that, aside from wind integration costs primarily concerning intra-hour changes, the other pertinent categories of net power costs are now so volatile that they cannot be captured by the Company's GRID production cost dispatch model. (Tr., Vol. III, pp. 549-552, 554.) Bird argued that "[t]he goal of the company's ECAM proposal is simply to restore that original intent in setting base rates to true up rates so that the rates reflect prudently incurred costs, no more and no less." (Tr., Vol. III, p. 549.) He contended that the current PCAM and the proposals by OCA and WIEC could create a circumstance where the Company would recover more than its prudently incurred costs. Bird argued that the Company's proposed ECAM further reduces risk to customers because it properly incents RMP to invest in resources that will produce the lowest long-term costs to customers on a risk-adjusted basis by creating the expectation that RMP has a legitimate and reasonable opportunity to earn its authorized ROE, thereby recovering the cost of its investments. (Tr., Vol. III, p. 552.) Bird concluded his testimony saying, "In summary, this mechanism is extremely important to the Company and to the customers we serve in Wyoming, in particularly in light of the current and dramatic build cycle that we are in." (Tr., Vol. III, p. 554.)

54. Bird agreed that the mechanisms proposed by OCA and WIEC would allow the Company the opportunity to achieve its authorized ROE. He acknowledged that RMP's own generation resources, the long-term and in-house nature of portions of its fuel supply, and its aggressive hedging practices all mitigate a significant amount of its exposure to net power costs volatility. He also agreed RMP has control over its resource acquisitions and hedging strategies, but he noted that RMP has this control only over its exposure to risk from price volatility for a given forecast. He stated factors like wind and rain were inherently difficult to predict and therefore hedge against. Bird stated that, regarding dollar cost averaging over a 48-month period, hedging over a longer time period provides customers with stabilization and minimization of extreme volatility they would otherwise be exposed to. It also provides benefits through the ECAM by minimizing the amount of variance that would show up in the ECAM deferral balance. (Tr., Vol. III, pp. 556-558, 577-578, 590-591.) Bird acknowledged the Company has reserve margins on the generation side to deal with unexpected generator outages. Further, RMP's transmission system is designed to deal with unexpected outages to ensure the Company meets its obligations to provide service. Bird noted that there are nevertheless costs associated with forced outages. He conceded that: [i] without the Company's best efforts, net power costs would be higher; and [ii] customers rely on the Company to control its net power costs. Bird suggested that the issue in prudency reviews would be whether the Company had

managed the event in the best possible manner. Bird agreed that a prudency review ". . . is a sufficient mechanism to ferret out or to thoroughly examine and determine if power costs have been appropriately forecasted, established in the rate case and subsequently purchased." According to Bird, a sharing band or a dead band provides no incentive for the Company to control its net power costs. He stated all they accomplish is a disallowance of the Company's prudently incurred costs. (Tr., Vol. pp. 559-564, 573, 586-589, 592-565, 600, 605-606.)

WIEC

55. Kevin Higgins, a principal in the Energy Strategies consulting firm, testified for WIEC in general and in support of his prefiled direct testimony. (WIEC Exhibit 201.) He disagreed with RMP's proposal to replace the existing PCAM with the proposed ECAM, and asked the Commission to reject it. In his opinion, the ECAM would seriously reduce the Company's incentive to manage its fuel and purchased power costs as well as it would if it remained more responsible for the energy cost risk. (Tr., Vol. II, p. 299.) He disagreed with RMP's assertion that a prudency review would incent RMP to ensure sound cost management practices, stating:

> In my view, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for the company having skin in the game when it comes to managing its costs. A finding of imprudence essentially requires a determination that the company acted unreasonably in its power cost management.
>
> In contrast, a risk sharing mechanism structured such that each and every action undertaken by the company affects its bottom line provides an incentive for the company to get the best possible result from every action. (Tr., Vol. II, pp. 299-300.)

According to Higgins, a well-crafted sharing mechanism would allow the Commission to harness the natural economic self-interest of the Company to incentivize the desired behavior through the mechanism in which risks and benefits are more properly balanced. (Tr., Vol. p. 300.)

56. Higgins strongly disagreed with RMP witness McDermott's support for the proposed ECAM based on the contention that net power costs are volatile, unpredictable and largely beyond the Company's control. Higgins testified that he believed McDermott overstated his claim because [i] McDermott's analysis of volatility largely focuses on price movements in commodity markets in which the Company does not have significant price exposure; [ii] RMP's exposure to power cost volatility is mitigated significantly by the composition of its generation resources, the long-term and in-house nature of much of RMP's fuel supply, and its aggressive hedging practices, each of which Higgins found to be entirely overlooked or given little attention; [iii] McDermott's claim of net power cost volatility failed to consider the role played by the Company's relatively frequent rate case filings in Wyoming; and [iv] McDermott's analysis of net power cost volatility is heavily skewed by his inclusion of the impacts of the California power crisis of 2000-2001 and the market manipulation associated with that period. Higgins stated that, when the distorting effects of the power crisis and associated market manipulation are removed from McDermott's analysis, there is little difference between McDermott's volatility metric for net power costs and non-net power costs. Higgins testified

that, while he agreed with RMP that net power costs are impacted by weather-related risk, forced outages and resource portfolio risk, he believed these risks fall within the purview of normal business risks faced by the Company and for which it is compensated through its return on equity (ROE). (Tr., Vol. pp. 300-302, 327-328.) With regard to prudency reviews, Higgins stated he did not believe a prudency review provided a very strong incentive. (Tr., Vol. II, pp. 326, 333-334.) Higgins believed WIEC's proposed PCAM provided a more balanced and reasonable approach to net power costs and was a better approach to the risk-sharing precepts in the Commission's order in Sub 230. (Tr., Vol. p. 302.)

57. Michael Gorman, Consultant and Managing Principal with Brubaker and Associates, Inc., testified on behalf of WIEC and in support of his prefiled testimony. (WIEC Exhibit 202.) He commented on RMP's credit rating review in light of the proposed ECAM. Gorman noted that credit rating agencies generally review a utility's credit standing which includes a review of the predictability of cash flows to support its financial obligations. He stated that credit rating agencies, including S&P, Moody's and Fitch, specifically recognize RMP's PCAM in Wyoming as "credit supportive" for PacifiCorp in helping to ensure recovery of power costs. Gorman stated that, as part of the review undertaken to determine the appropriate assessment of a utility's operating risk, credit rating agencies will [i] perform stress tests on baseline cash flows, [ii] consider and review regulatory mechanisms in place to recover the differential in power costs when the rates are actually in effect, and [iii] review mechanisms or options the utility has in place to manage power cost price uncertainty when rates are in effect. (Tr., Vol. III, pp. 435-436, 440-445, 449-451, 462-467.) Gorman discussed the Company's off-balance sheet debt noting that both the current PCAM and the proposed ECAM reduce PacifiCorp's off-balance sheet debt. He stated WIEC's proposed PCAM mechanism reduces RMP's off-balance sheet debt obligations by providing a mechanism that is above and beyond traditional ratemaking to ensure that the utility can largely recover its power cost obligations and meet its fixed obligations. (Tr., Vol. III, pp. 436-437.)

58. Gorman discussed cost of service measures that RMP and PacifiCorp have undertaken to manage net power costs price variability risk and maintain an investment grade bond rating. He stated that the Company modified its capital structure in order to manage its cost structure to reflect the risks associated with net power costs. PacifiCorp has increased its common equity portion of total capital in rate proceedings. Its capital structure has gone from about 50 percent equity to over 50 percent equity. Gorman stated that rates are generally set using a capital structure containing about a 50 percent common equity. Gorman stated that increasing the common equity ratio in the capital structure reduces financial risk to help balance total investment risk with the operating risk related to not being given full guaranteed recovery of power costs. Gorman testified:

> By increasing the common equity ratio of total capital, even if you leave the security pricing components alone, which would be the objective by balancing interest, you're still raising the cost of capital. That higher cost of capital is then passed on to customers. So customers are paying a higher financial cost to offset the higher operating cost risk the utility has for assuming some purchased power cost recovery risk.

So it's a component of the overall risk assessment of the utility, and it does result in higher costs to customers.

So while the purchased power cost recovery risk does have implications on the utility, those implications are generally pushed off onto retail customers in the form of price structures that ensures that the financial and operating risk of the utility are structured in a way that it maintains investment grade credit quality. That has been accomplished here. (Tr., Vol. III, p. 438.)

Gorman stated that pricing structure to retail customers has be competitive and has to be stable in a way that allows retail customers to compete in their own marketplaces and be able to afford to pay their utility. Gorman stated this was also important to maintaining investment grade credit quality. (Tr., Vol. III, pp. 437-439, 451-453, 456.)

59. Gorman stated that, under WIEC's proposal, forecasted power costs will be used to set rates with the expectation that those forecasts are the best estimate available of what the actual power costs will be. In these circumstances, it is expected that the rates implemented will fully recover costs while giving the Company the opportunity to earn its authorized rate of return. In WIEC's plan, if power costs are much different than those forecasted, the difference between power costs built into rates for the time period and what the Company actually incurred will be apportioned between customers and shareholders. Gorman stated that, when RMP forecasts power costs, it can also lock in a lot of those commodity prices for the forecast period. The Company can then come back in a year, and lock in the commodity prices in their forecast prices for the following year using hedging instruments. He stated being able to lock in commodity exposure for the following year and being permitted to use that forecast to set rates provide a very high level of assurance of recovery of commodity costs. Under the WIEC proposal, there is risk for the utility management if the utility has the ability to lock in power costs at the base rate level and it does not execute those hedges. Gorman stated the utility would lose if power costs differ from what was forecast. (Tr., Vol. pp. 467-473.) Gorman contrasted the RMP and WIEC proposals. In his opinion, the Company's proposal would be more credit-supportive, because it provides more assurance of cost recovery. However, Gorman found no evidence that adoption of the RMP proposal ". . . would result in a stronger credit rating than if WIEC's proposal was adopted." (Tr., Vol. III, pp. 473-476.)

60. Randall Falkenberg, President of RFI Consulting, Inc., testified for WIEC and in support of his prefiled direct testimony. (WIEC Exhibit 203.) He disagreed with RMP's contention that anything other than cost-plus regulation would inevitably result in under-recovery, stating the system of allowing the Company to use forecasted power costs coordinated with the rate-effective period would largely eliminate substantial deviations in under- and over-recoveries. According to Falkenberg, there is nothing to suggest that cost models could not be calibrated and employed correctly to produce an unbiased forecast to power costs. In Falkenberg's opinion, the current PCAM has worked well and, because it has worked well for Wyoming, Wyoming should not look to other states for guidance on how to implement a proper mechanism. Falkenberg said other states should be looking at Wyoming. He was of the opinion that WIEC's proposed PCAM was, as noted by Gorman, reasonable as it updates the current PCAM. It has been recalibrated to reflect a change in the size of the Company's power costs on

the system and its investment base. WIEC added to the current PCAM structure features comparable to the Oregon mechanism wherein the Company can take its power cost study, coordinate it with the rate-effective period, and use a forecasted model. WIEC's proposal adds a safety net that protects both the Company and its customers in the event of unexpected deviations in power costs. (Tr., Vol. III, pp. 481-483, 512-513.) Falkenberg explained:

> The mechanism would work by allowing in general rate cases the company to set the baseline and give – and the company would have the full and fair opportunity to earn the return approved by the Commission. But if deviations exist that are much larger than the normal course of business, the company could recover increasing amounts of that or the ratepayers would be refunded increasing amounts of that. (Tr., Vol. III, p. 483.)

61. Regarding interjurisdictional allocation, Falkenberg noted that RMP has filed a request for changes to the existing protocol that would eliminate some of the allocators used in the current method. Falkenberg stated WIEC would more strictly rely on the SE and SG factors as they would eliminate the need for a true-up of the embedded cost differential (ECD). Use of the Company's proposed method in the last PCAM filing would have made a difference of several million dollars had the SE factor been used. The PCAM that Falkenberg recommends would be based on the methodology that the Company has used in the last several years but would update it to reflect the allocation methodology approved by the Commission. WIEC's proposal also includes doubling the dead band and doubling the width of the sharing band. (Tr., Vol. III, pp. 483, 493-495,497, 506-507, 513-514.) Falkenberg further recommended that, regardless of which mechanism the Commission approves, it should impose the minimum filing requirements for ECAM applications proposed by WIEC. (WIEC Exhibit No. 203, p. 33, Exhibit (RJF-2); Tr., Vol. III, pp. 498-502, 507-509.)

62. Falkenberg expressed a preference that net power costs be set in a general rate case because there is more time for review. (Tr., Vol. III, p. 509.) Falkenberg also discussed his belief RMP overstated the amount by which claims to have under-recovered from 2001 to 2009 because its figures did not include the PCAM adjustments or the PCAM settlement. He stated a large amount of the under-recovery experienced by the Company was the result of rate case settlements and some of the decisions the Company made, particularly the initial decision to settle and forego some recovery in order to get the PCAM established. He said he believed the Commission's approval of the PCAM stipulations was in the public interest. (Tr., Vol. III, pp. 515-520.)

OCA

63. Denise K. Parrish, OCA Deputy Administrator, summarized her prefiled direct testimony and cross-answer testimony (OCA Exhibits 301 & 302) and presented the OCA's recommendations and concerns about the ECAM. Parrish addressed, *inter alia*, the amount of costs that had been shared between shareholders and ratepayers over the three-and-a-half year period that the current PCAM has been in place. According to Parrish's computation, RMP shareholders have paid approximately 5 to 10 percent of those total costs. (Tr., Vol. II, pp. 355-357.) She stated that OCA's proposal differs from RMP's proposal to share 5 percent of the true-up differential in that OCA proposes to share 5-10 percent of the total net power costs,

rather than sharing the difference between forecasted and actual net power costs. (Tr., Vol. II, p. 357.) She suggested that there be no less sharing than has occurred under the current PCAM and that a target be set of about 10% of the total cost to go to shareholder and the remaining 90% to be paid by the ratepayers. While net power costs are growing, Parrish believed they are not necessarily more volatile or less controllable than in the past. (Tr., Vol. II, pp. 357-358.) Parrish also recommended that renewable energy credit (REC) and SO_2 allowance revenues be credited in their entirety to ratepayers on the grounds that the capital and operating costs giving rise to those credits are paid in customers' rates. (Tr., Vol. II, pp. 359-363, 379-382.) Parrish could accept a proposal which eliminated the dead band. She agreed that the issue would then become determining the proportions of the sharing band. She recommended that her 90/10 sharing target be structured so that forecast power costs are placed into base rates (much like current practice) and any differential between those forecast costs and the actual costs would be shared 50% to shareholders and 50% to customers. (Tr., Vol. II, Pp. 367-373, 377-379, 387.)

64. Parrish acknowledged she had not prepared an analysis of the differences between the allocation methodologies proposed by RMP and WIEC. She stated she still foresees a pitfall if the SE allocation factor were used and were to change dramatically. She stated, after hearing RMP's and WIEC's arguments, that she preferred RMP's proposal because of its simplicity. (Tr., Vol. II, pp. 382-387.) Regarding prudency reviews, Parrish stated she believed it could be an incentive for a company to control costs. She did not oppose WIEC's suggestion for minimum filing requirements as long as the Company filed the necessary documents for review and did not stymie parties' efforts to get additional information if requested. Parrish did not agree with WIEC's proposal to exclude the ECD calculation from the true-up, explaining that, unless there is to be a completely different methodology like that proposed by the Company, the ECD is an integral part of the method. (Tr., Vol. I, pp. 388-389, 401.)

65. Parrish stated that both the WIEC and OCA proposals put a portion of the cost recovery at risk through either the sharing and dead band or sharing proposals, respectively. Parrish stated both proposals provide RMP with the opportunity to fully recover its net power costs through allowing forecast base net power costs to be incorporated into base rates coupled with the ECAM mechanism that is proposed. (Tr., Vol. III, pp. 426-427.) To her, the salient differences between the OCA and WIEC proposals was that WIEC proposed safety net provisions, dead bands, and incentives such as the true-up provision. OCA's proposal focuses on the incentive and cost recovery provisions and does not include a dead band. Parrish stated OCA's incentive provision is the same as described by WIEC witness Higgins relative to encouraging the Company to do the best possible cost containment while at the same time having established base net power costs in a general rate case based on the best numbers available without any sort of discounting. In the table at page 10 of her pre-filed cross-answer testimony, she provided a comparison of each party's proposal and the resulting impacts of the proposals at different levels of variance in actual costs from a base of $1 billion. Her table included total company numbers while WIEC witness Falkenberg used state-specific numbers in his testimony. Parrish explained that, based on the OCA's proposal, if there is a $100 million (10%) change from base net power costs of $1 billion, shareholders would be responsible for $50 million and ratepayers would pay $50 million of the variance. In total, ratepayers would pay $1,050,000,000 and shareholders would be responsible for $50 million. Under the WIEC proposal, because of the proposed dead and sharing bands, ratepayers would pay $1,014,000,000, and under RMP's

proposal, ratepayers would pay $1,095,000,000. Under the 10% change example Parrish discussed, the OCA proposal would require shareholders to pay 5% and the WIEC proposal would have shareholders pay 8%. Parrish noted these results would change as the variance of actual net power costs from the base increases and the dead and sharing bands assign different levels of cost responsibility to shareholders and ratepayers. (OCA Exhibit 302, p. 10; Tr., Vol. II, pp. 427-433.)

Legal Standards Applicable In This Case

66. W.S. § 37-2-121 provides the standard which rates must meet and allows utilities to propose innovative rate making procedures for Commission consideration:

> If upon hearing and investigation, any rate shall be found by the commission to be inadequate or unremunerative, or to be unjust, or unreasonable, or unjustly discriminatory, or unduly preferential or otherwise in any respect in violation of any provision of this act, the commission, within the time periods provided under W.S. 37-3-106(c) may fix and order substituted therefor a rate as it shall determine to be just and reasonable, and in compliance with the provisions of this act. The rate so ascertained, determined and fixed by the commission shall be charged, enforced, collected and observed by the public utility for the period of time fixed by the commission. The rates may contain provisions for incentives for improvement of the public utility's performance or efficiency, lowering of operating costs, control of expenses or improvement and upgrading or modernization of its services or facilities. Any public utility may apply to the commission for its consent to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission may consider and approve proposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services, facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest.

We note that applications considered under this statute must meet the substantial evidence standard rather than the higher and more commonly used preponderance of the evidence standard which applies to other Public Service Commission decisions.

67. Under W.S. § 37-2-112, the Commission has ". . . general and exclusive power to regulate and supervise every public utility within the state in accordance with the provisions of this act." It has broad powers of inquiry into utilities and their business. *See, e.g.*, W.S. §§ 37-2-116, 37-2-117, and W.S. § 37-2-119.

68. The Wyoming Supreme Court discussed the role of the public interest in Commission decisions in *PacifiCorp v. Public Service Commission of Wyoming*, 2004 WY 164, ¶13, 103 P.3d 862 (2004), the Court quoted with favor *Sinclair Oil Corp. v. Wyoming Public Service Comm'n*, 2003 WY 22, ¶9, 63 P.3d 887, ¶9 (Wyo. 2003):

> Speaking specifically of PSC, we have said that PSC is required to give paramount consideration to the public interest in exercising its statutory powers to regulate and supervise public utilities. The desires of the utility are secondary. *Tri County Telephone Ass'n, Inc. v. Public Serv. Comm'n*, 11 P.3d 938, 941 (Wyo. 2000) (citing *Mountain Fuel Supply Co. v. Public Serv. Comm'n*, 662 P.2d 878, 883 (Wyo. 1983)). Additionally, in recognition of the limited nature of our review, we have explained that the judicial function is exhausted when we can find from the evidence a rational view for the conclusions of the PSC. *Tri County Telephone Ass'n*, at 941 (citing *Telstar Communications, Inc. v. Rule Radiophone Serv., Inc.*, 621 P.2d 241, 246 (Wyo. 1980)).

Construing W. S. § 37-3-101, which requires rates to be reasonable, the Court in *Mountain Fuel Supply*, 662 P.2d at 883, commented that:

> This court cannot usurp the legislative functions delegated to the PSC in setting appropriate rates, but will defer to the agency discretion so long as the results are fair, reasonable, uniform and not unduly discriminatory.

Later, 662 P.2d at 885, the Court in *Mountain Fuel* stated that:

> We agree that if the end result complies with the 'just and reasonable' standard announced in the statute, the methodology used by the PSC is not a concern of this court, but is a matter encompassed within the prerogatives of the PSC.

In accord are *Great Western Sugar Co. v. Wyo. Public Service Comm'n and MDU*, 624 P.2d 1184 (Wyo. 1981); and *Union Tel Co. v. Public Service Comm'n*, 821 P.2d 550 (Wyo. 1991), wherein the Supreme Court stated, 821 P.2d at 563, that it ". . . has recognized that discretion is vested in the PSC in establishing rate-making methodology so long as the result reached is reasonable."

69. W.S. § 37-2-120 requires the Commission to afford due process in its cases, stating that:

> No order, however, shall be made by the commission which requires the change of any rate or service, facility or service regulation except as otherwise specifically provided, unless or until all parties are afforded an opportunity for a hearing in accordance with the Wyoming Administrative Procedure Act.

70. The Wyoming Administrative Procedure Act, at W.S. § 16-3-107, sets parameters for due process in Commission cases, including the giving of reasonable notice. In accord are W.S. §§ 37-2-201, 37-2-202, and 37-3-106. *See also,* Sections 106 and 115 of the Commission's Rules.

Additional Findings of Fact

71. Many of the specific facts necessary to the decision reached in this case have been stated above and will not be restated here.

72. To replace the current PCAM, RMP has proposed the ECAM under W.S. § 37-2-121 as a form of nontraditional ratemaking. The predecessor PCAM was authorized by the Commission as a form of nontraditional ratemaking in 2006. The ECAM application raises the issue as to how far the Commission may go to modify an applicant's proposal; and RMP has shown openness to modifications to the ECAM as discussed below in our conclusions of law. This demonstrates the Commission has some flexibility to find reasonable solutions, *inter alia*, in the form of a sharing band which yields a more favorable result than the current PCAM.

73. With the ECAM, RMP seeks recovery of its net power costs, arguing that they are volatile and very difficult to predict accurately. The Company has asserted that there has consistently been a shortfall in forecasted costs in the range of 3% to 8% annually. WIEC, on the other hand, contends the Company is overstating this volatility. Presently, RMP is insulated to a degree from the volatility of net power costs because it is allowed to forecast and collect power costs in a forward-looking rate effective period. (Tr. Vol. III, p. 481.) The Company, however, argues that setting rates on a forecasted basis is not sufficient because certain categories of net power costs are so volatile they cannot be accurately forecasted by the Company's GRID model. The issue, as far as the Company is concerned, is the discrepancy between forecasted costs and costs actually incurred. The Commission previously addressed this discrepancy with the PCAM, which was conceived as a mechanism for sharing the risk of cost increases rather than as a mechanism for passing through to net power costs to customers. RMP now seeks to pass through net power costs and argues that the current PCAM functions to disallow some prudently incurred costs. It finds fault with two aspects of the PCAM. The first problem is a dead band, a range of costs for which no recovery of the difference between actual and forecasted costs is allowed. The second problem is with the sharing bands, or a range of costs in which the cost differential is shared between the Company and its customers.

74. RMP has proposed an ECAM which will dispense with the dead band and reduce the sharing bands to a single 95%/5% sharing band. The Company has not offered support for the derivation of these percentages, clearly offering it only as an accommodation, and arguing that ideally it should recover 100% of its prudently incurred costs from ratepayers. Parrish noted that the Commission has ". . . questioned whether those rules should apply to the self-generation portion of fuel and purchased power costs, and, in fact, in the past, the Commission has never applied those rules to a company's costs relative to fuel of self-generation. At least that's been the historical interpretation of those rules." (Tr. Vol. I, p. 362.) The Commission finds no reason to change this policy. Nevertheless, the Commission agrees that the dead band should be eliminated. The dead band concept shares risk, but it also results in an absolute denial of recovery for a portion of RMP's power costs, some of which may be wholly or partially outside of the Company's control. The Commission recognizes that, with the ECAM, it is moving beyond the risk sharing rationale of the PCAM toward -- but not to -- a pass-on structure. Therefore, the main issue in this case is the proportions of the sharing band.

75. In proposing a 95% sharing band, the Company would have the Commission rely heavily on an after-the-fact prudency review to insure the costs recovered were prudently incurred. The Commission disagrees that a prudency review should be the exclusive principle

whereby the Company's power cost decisions are considered. We agree with the testimony of Higgins that a simple prudency review is not a very strong incentive:

> [I]f you think about it . . . in terms of the grades you would get in school, if you have perhaps a D grade on what you're doing, you would still be able to pass a prudence review, whereas I think we want to incentivize utilities to aspire to be A students. And so I don't think there is a very great incentive to be an A student due to the threat of a prudence review. (Tr. Vol. I pp. 333-334.)

WIEC argued for something closer to best efforts. For RMP, Bird conceded that, without the Company's best efforts, net power costs would be higher. (Tr. Vol. III, p. 573).

76. In determining the sharing band in this case, the Commission notes the policies of our sister states. RMP serves six states, not all of which have adopted an ECAM or PCAM. During the testimony regarding the effect of the PCAM on the Company's credit reports it was noted that Wyoming's PCAM (even though it didn't recover 100% of RMP's costs) had a positive influence on the Company's credit ratings when contrasted to the lack of similar mechanisms in Utah, Washington and Idaho. (Tr. Vol. II, p. 182.)

77. Idaho has adopted an ECAM with a 90/10 sharing band and did so in the context of an historical test year. (RMP Exh. 9.) The Idaho ECAM also includes a $17.48 credit for customers. However, none of the parties compared the results of Idaho's ECAM with the one proposed in this case. (Tr. Vol. II pp. 320, 348.)

78. The Commission must also consider the high proportion of industrial load in RMP's Wyoming service territory. A disproportionately strict ECAM may impose a commercial disadvantage on Wyoming industry when compared to other jurisdictions which have weaker versions of the ECAM or none at all. The Company's expert, McDermott, conceded that commercial disadvantage is a proper consideration in this proceeding.

79. The Commission finds and concludes that the ECAM should be structured to provide incentives to the Company for four purposes: [i] to use the existing forecasting mechanisms; [ii] to encourage the accuracy of modeling supporting the forecasts; [iii] to avoid creating commercial disadvantage to roughly 70% of RMP's load in Wyoming, which would ultimately be detrimental to all Wyoming customers; and [iv] to encourage the Company to use its best efforts to control costs.

80. Commission Exhibit B compares the practical effect of the current PCAM with OCA's proposed 50/50 sharing band, WIEC's proposed mix of dead and sharing bands, and the Company's proposed 95/5 sharing band. (Commission Exhibit B.) Starting with base net power costs of $1 billion, it shows the effect of each method at various levels of net power costs, using intervals of $100 million above and below the base, i.e., variations at 10% intervals. For the Commission's purposes, the first 10% interval is the most important, in view of Duvall's testimony that the Company has been exceeding forecasts by 3% to 8%. Exhibit B shows the effect of the four alternatives both in the customer share of dollars and as a percentage of the net power costs. For example, when net power costs exceed the base by $100 million, the current

PCAM requires customers to bear an additional $42 million, or about 95% of total net power costs. The Company's proposal would require customers to bear an additional $95 million, and to bear about 99.5% of total net power costs.

81. This is a useful way to think about structuring the ECAM, because it starts with the thought that the Company can recover all base net power costs if it has prepared an accurate forecast. This encourages the Company to use existing forecasting mechanisms. Further, as long as a fixed proportion is used as a sharing band, the customer share of actual net power costs decreases as the gap between base and actual net power costs widens. So, if the discrepancy between base and actual power costs were $500 million (50%), the customer share of actual net power costs under the Company's proposal would be 98%, rather than 99.5% as in the case of a $100 million variation.

82. To the extent the Company can minimize the difference between forecasted base net power costs and actual net power costs, it avoids the effect of sharing bands entirely, and minimizes its own share of the difference between base and actual net power costs. This encourages the Company to prepare accurate forecasts and functions as an incentive to the Company to control costs.

83. For the foregoing reasons, the Commission finds that the reasonable sharing band is one that obligates customers to pay 70% of the difference between actual and base net power costs. This would require customers to pay $70 million of the first $100 million over the base, and 97.3% of total net power costs, if actual costs run 10% over base costs. This result is approximately halfway between the existing PCAM and RMP's initial proposal. The 70/30 proportion is the same one suggested by Higgins. (Trans. Vol. II, p. 347.)

84. Although the Commission prefers consistent treatment of net power costs in RMP's service territory, we have already noted that comparisons between and among states may be difficult, and consistency itself may prove elusive. *See supra*, paragraph 77. We accordingly do not expect lengthy treatment of this issue in RMP's annual filings.

85. Instead, the Commission concludes that the ECAM should sunset following Commission action on the fifth annual filing.[1] Should the Company wish to continue with the ECAM or a similar net power cost adjustment mechanism, we expect the Company to address the issue of consistent treatment of net power costs between and among the states.

86. Subjecting the ECAM to a sunset provision would also ensure a fresh look at the problems the Commission has been asked to address in this proceeding, and at subsequent

[1] Commissioner Lewis, otherwise in full agreement with this decision, respectfully disagrees with the imposition of a sunset provision. In her opinion, annual ECAM proceedings would subject the mechanism to thorough review and such modification as changing circumstances and the public interest require, while avoiding the possibility that RMP will, after five years, find it necessary to initiate a complex, costly proceeding to extend or replace the ECAM for no reason but the arrival of the sunset date.

circumstances which may warrant changed policies. Such circumstances may include, *inter alia*, significant modifications to the Company's present plans for investment in transmission; significant modifications to the Multi-State Protocol; federal intervention in the allocation of costs for transmission projects; and intolerable cumulative effects of rate increases.

87. RMP proposes a simpler method for calculating the difference between base and actual net power costs. (RMP Exh. 11; Tr. Vol. 1, p. 66). WIEC testified that this new method would have resulted in a difference of several million dollars had it been used in the last PCAM filing. As important, the Commission finds that RMP did not create a record sufficient to show there would be little divergence between the "simpler" method and the pending Multi-State Protocol revision. The Commission finds the only supportable method of interjurisdictional cost allocation is the one which results from Multi-State Protocol, currently before the Commission for revision in Docket No. 20000-381-EA-10. The Commission notes that RMP represented it would not object to this decision. (Tr. Vol. I, p. 690.)

88. RMP proposed to establish base net power costs in an ECAM. The Commission has an interest in implementing a consistent policy regarding the architecture of forecasted rates and in consistent and accurate information. Allowing the Company to establish NPC outside of the context of a general rate case through a separate and complex application in an ECAM docket would frustrate this interest. Instead the Commission will direct the Company to establish base net power costs in general rate cases where all of the relevant factors can be thoroughly and accurately examined.

89. In its 2007 PCAM application, the Company's proposed actual net power costs were slightly less than $400 million; by 2010, the comparable figure exceeded $1 billion. This increase has been accompanied by similarly substantial investments in infrastructure. During such times, it becomes more difficult to discern patterns that could be described as normal. It is nonetheless worthwhile to attempt to do so. So, if forecasting remains valuable, modeling remains valuable as well; and, in this complex area, consistency is independently valuable. We believe we should encourage the use of data sets that are consistent from year to year where possible. In this regard, Duvall indicated that the net power cost components have not changed over time. (Tr., Vol. I, p. 118.) Because of this, we reject WIEC's suggestion that wheeling revenues be included in net power costs for the sake of matching costs with revenues. (Tr., Vol. III, p. 501.) We find it is wiser to leave the treatment of wheeling revenues and expenses as they are.

90. The Commission notes the Company did not intend to forecast RECs or SO_2 credits as components of base net power costs. (*See* Exhibit GND-2, Note 1.) One result of this method of including these credits in the ECAM is that the Company will have full use of any cash generated from these credits until the interim ECAM rates go into effect, a result which arguably differs in spirit from the type of commodity balancing account which appears in the Commission's Rule 250. The Commission expressly approves this result, with the thought that the Company may find some incentive in the arrangement, though not as lucrative an incentive as the Company would wish. (Tr. Vol. III, pp. 608-609.)

91. The Commission concurs with the OCA's argument that 100% of the value of RECs and SO_2 credits should be allocated to customers because the capital and operating costs

giving rise to these credits are included in customers' rates. Therefore, to ensure proper credit for these credits, the Commission will direct the Company to ignore RECs and SO_2 credits in its initial calculation of the customer share of the actual net power costs, using the 70/30 sharing band. Once the customer share is determined for actual net power costs exclusive of the credits, a separate calculation will be made in order to allocate the full Wyoming share of the credits to customers.

92. In addition to the rationale articulated by OCA's Parrish, the Commission believes that full allocation of the credits is a reasonable component of a package which eliminates dead bands, and which in total may be more supportive of the Company than the arrangements provided by sister states. It may help to ease burden on customers from the Company's plans for recurring rate increases, even though the legal structure underlying the renewable energy credits may be subject to modifications which sharply decrease or even eliminate their value.

93. The Commission will require sixteen items of supporting information with each annual ECAM application. The list of these filing requirements is attached hereto and incorporated herein as Attachment A. The Company may include any additional information, but it must incorporate and fully explain the items on the list. The list of minimum filing requirements is not intended to limit discovery in an ECAM proceeding. It is intended to expedite initial discovery.

94. The Commission accepts WIEC's suggestion that the Company provide, with the ECAM application, a true-up of authorized revenues and recoveries. The Company acknowledged this request was reasonable, and in so doing, again acquiesced in a variance from its original ECAM concept. (Tr. Vol. I, p. 100.)

95. The Company supported its proposal that the ECAM rates become effective on an interim basis two months after filing. This means, however, that there will be no other limits on the review period beyond those provided by statute and the Commission's Rules. Even if ECAM applications do not establish base net power costs, they will be sufficiently complex that this approach to review is necessary.

Conclusions of Law

96. RMP is duly authorized by the Commission to provide retail electric service as a public utility in its Wyoming service territories under certificates of public convenience and necessity issued and amended by the Commission. It is an electric public utility as defined in W.S. § 37-1-101(a)(vi)(C). The Commission therefore has the general and exclusive jurisdiction to regulate RMP as a public utility in Wyoming under W.S. § 37-2-112

97. Proper public notice of these proceedings was given in accordance with the Wyoming Administrative Procedure Act, W.S. § 37-2-203 and the Commission's Rules, especially Section 106 thereof. The public hearing was held and conducted pursuant to the provisions of W.S. §§ 16-3-107, 16-3-108, 37-2-203, and applicable sections of the

Commission's Rules. WIEC's intervention was properly granted. It and the OCA became parties to the case for all purposes.

98. The proposed ECAM constitutes a form of nontraditional ratemaking allowed to be considered by the Commission under W.S. § 37-2-121. The original PCAM was authorized as a nontraditional ratemaking tool in our March 24, 2006, *Order* in Docket No. 20000-230-ER-05. The statutory formula of W.S. § 37-2-121 states that:

> *[a]ny public utility may apply* to the commission for its *consent* to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission *may consider and approve* proposals . . . which can be shown by substantial evidence to support and be consistent with the public interest. [Emphasis added.]

Thus, the statute offers a modicum of protection for a utility from being forced into undesired "innovation" by the Commission or others. It also opens the door to conscientious innovation by allowing proposals to be judged by the substantial evidence standard. The instant application raises the issue of how far the Commission may go to modify RMP's proposal in its role of considering and approving. In this case, we are guided by two considerations:

a. First, RMP has demonstrated that it is willing to accept less than a full 100% recovery of its incurred net power costs by proposing a 95/5 sharing band. The Company has shown flexibility on other details of its proposal, such as the approach to interjurisdictional allocations. (Tr. Vol. I, p. 69.) Elsewhere, RMP has agreed that it would be open to other modifications of the proposed ECAM. This demonstrates the Commission has some flexibility to find a reasonable solution in the form of a sharing band which yields a more favorable result than the current PCAM.

b Second, while the Commission may reject the Company's proposal outright, that would leave the Company in a worse position than it is in under the PCAM. This is particularly true given the fact the PCAM has expired, leaving only it last iteration to run its course as discussed hereinabove. The ECAM application may thus be viewed as seeking a modification of the existing PCAM, and allowing considerable latitude to modify the proposed adjustment mechanism. For these reasons the proposal before the Commission in this case is in a sense incremental, although we are mindful that we ought not to *replace* RMP's ECAM with one entirely of our own making.

99. The substantial evidence of record, as discussed herein, supports the Commission's conclusion that the Company's proposed ECAM should be approved as modified by this *Order*. The result serves the public interest and should be approved pursuant to the Commission's authority under W.S. § 37-2-121 to authorize the use of nontraditional rate making methods.

100. Based upon its review of the application and the testimony offered in support thereof, the Commission concludes the ECAM provisions, and terms and conditions as contained in the application and modified herein, represent a just and reasonable resolution of all

outstanding issues before the Commission in these proceedings. Our decision serves the public interest.

101. The Commission concludes that the resultant ECAM will allow RMP to continue to provide adequate, safe, and reliable service and will result in just and reasonable rates.

IT IS THEREFORE ORDERED:

1. Pursuant to the Commission's deliberations held on January 5, 2011, the application of Rocky Mountain Power for authority to implement an Energy Cost Adjustment Mechanism is approved as modified herein.

2. The revised tariffs discussed hereinabove, not already approved by the Commission, shall be filed with the Commission for approval, consistent with the terms of this *Order*, within two weeks of its issuance.

3. The parties shall promptly hereafter deal with all confidential information in their possession in accordance with and at the time specified in ¶6(e) of the Commission's *Protective Order*, issued in this docket on April 16, 2010.

4. This *Order* is effective immediately.

MADE and ENTERED at Cheyenne, Wyoming, on February 4, 2011.

PUBLIC SERVICE COMMISSION OF WYOMING

ALAN B. MINIER, Chairman

STEVE OXLEY, Deputy Chairman

(SEAL)

KATHLEEN A. LEWIS, Commissioner

Attest:

STEVE MINK, Assistant Secretary

ATTACHMENT A
ECAM Minimum Filing Requirements

1. All Short-Term Firm Transactions.
2. Actual market prices for the period for all energy trading markets in which PacifiCorp participated.
3. Actual natural gas market prices and any natural gas contract executed.
4. New or Modified contracts for Long-Term Firm power purchases or sales.
5. Summary of terms and prices for any new or modified coal contract.
6. To the extent included in ECAM, all monthly California ISO service charges and fees.
7. Support for the interest rate calculation used in the ECAM filing.
8. Actual monthly wheeling expenses and revenues.
9. A summary of all settlements, liquidated damages, fines or penalties included in the ECAM calculations.
10. Provide a summary of RECs including when each is generated, reserved and sold for all of PacifiCorp, categorized by state, with the prices therefor.
11. The identity of all wholesale sales contracts where RECs were bundled with energy, including supporting documentation for the revenue split between the energy and REC.
12. A summary of all SO_2 contracts.
13. Coal and wind generating plant operations data including availability, capacity factor, Equivalent Forced Outage Rate (EFOR), and hourly generation.
14. A report reconciling recovered ECAM revenues compared to the per rate class revenues authorized by the Commission in the prior period ECAM and the per rate class revenues actually collected, including authorized and actual revenues per class and illustrating the differences between the forecasted and actual billing units.
15. The estimated wind integration costs in the current ECAM and supporting documentation for the calculations.
16. A report of daily transactions supporting the system capacity and energy balance for Pacific Power and RMP for the ECAM period.

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism	)))))))	DOCKET NO. 09-035-15 CORRECTED REPORT AND ORDER

ISSUED: March 3, 2011

SHORT TITLE

Rocky Mountain Power Energy Balancing Account

SYNOPSIS

The Commission approves an energy balancing account for PacifiCorp, doing business in Utah as Rocky Mountain Power, pursuant to the statutory requirements of Utah Code § 54-4-13.5. PacifiCorp may begin implementation of this balancing account at the conclusion of the pending general rate case, Docket No. 10-035-124.

Nature of Corrections: The locations of the formulas in the "Discussion, Findings and Conclusions" section, item D. "Balancing Account Calculation" are corrected. Also the document is repaginated and the Table of Contents is corrected.

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APPEARANCES

Gregory B. Monson, Esq. Stoel Rives, LLP	For	PacifiCorp
Yvonne Rodriguez Hogle, Esq. Rocky Mountain Power	"	"
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Steven S. Michel, Esq. Chief Counsel, Energy Program	"	Western Resource Advocates
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Eric Jonathan Lacey, Esq Brickfield, Burchette, Ritts & Stone, P.C.	"	Nucor Steel-Plymouth, A Division of Nucor Corporation

I. PROCEDURAL HISTORY

On March 16, 2009, PacifiCorp, doing business in Utah as Rocky Mountain Power, ("Company") filed with the Public Service Commission of Utah ("Commission") an application for approval of its proposed energy cost adjustment mechanism ("proposed ECAM"). On April 14, 2009, the Commission held a duly noticed scheduling conference, leading to an April 22, 2009, scheduling order. Pursuant to this order, the Commission held a technical conference on May 5, 2009, and received comments and recommendations on May 26, 2009, from interested parties regarding the scope of issues to be addressed in this docket. Also on April 22, 2009, the Commission issued a protective order governing the disclosure of confidential material.

The Utah Division of Public Utilities ("Division") and the Utah Office of Consumer Services ("Office") actively participated in the initial technical conference and in each succeeding phase of this proceeding. Additionally, between April 13, 2009, and June 15, 2009, the following parties petitioned for, and were granted, leave to intervene: Holcim, Inc., Kennecott Utah Copper Corp., Kimberly-Clark Corp., Malt-O-Meal, Praxair, Inc., Proctor & Gamble, Inc., Tesoro Refining and Marketing Co., and Western Zirconium, referred to collectively as "Utah Industrial Energy Consumers" ("UIEC"); Utah Association of Energy Users ("UAE"); Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, "Wal-Mart"); Salt Lake Community Action Program ("SLCAP"); Western Resource Advocates ("WRA"); Utah Clean Energy ("UCE"); the International Brotherhood of Electrical Workers, Local 57 ("IBEW"); and Nucor Steel-Plymouth, a Division of Nucor Corporation ("Nucor").

On June 18, 2009, the Commission issued a procedural order providing guidance based on the parties' comments regarding the scope of issues. In this order the Commission noted the issues raised were numerous, relatively complex, and would require careful consideration of the evidentiary record to ensure the public interest is served. In order to address these issues in a comprehensive yet timely manner, the Commission's order adopted a phased approach to the evidentiary hearings. In "Phase I" the Commission would examine the present need for some form of energy balancing account. If the weight of the evidence demonstrated such need, the Commission would then consider in "Phase II" the parties' recommendations as to the design and implementation of the Company's proposed ECAM, and other forms of energy balancing accounts.

On August 4, 2009, following a duly noticed scheduling conference, the Commission established the schedule for the Phase I proceeding. Between August 18, 2009, and January 6, 2010, the parties prepared and distributed four rounds of written testimony, beginning with the filing of supplemental direct testimony by the Company, followed by the direct testimony of the other parties, and rebuttal and surrebuttal testimony. In all, the parties submitted several hundred pages of testimony and exhibits. The Phase I evidentiary hearing took place on January 12, 2010. The Commission also received public witness comments on that date.

On February 8, 2010, the Commission issued a report and order giving the parties notice the case would proceed to Phase II to consider the Company's proposed ECAM and any modifications or alternatives parties might propose. While several parties objected to implementation of an energy balancing account under any circumstances, the Commission found the Phase I evidence supported a conclusion that a properly designed energy balancing account could be in the public interest. The Commission further found that a final conclusion on the public interest question necessarily depended upon a number of issues not sufficiently developed in Phase I.

On February 9, 2010, the Company filed a motion requesting deferred accounting for the difference between certain net power costs allowed in the rates to be established in the Company's general rate case, Docket No. 09-035-23,[1] and certain actual net power costs incurred after February 18, 2010. Between February 22, 2010, and February 24, 2010, the Division, Office, UAE and UIEC filed memoranda in opposition to the Company's motion. On March 8, 2010, the Company filed a response to the parties' opposition to its motion.

On February 22, 2010, UAE filed an application for deferred accounting of incremental renewable energy credit ("REC")[2] revenue in Docket No. 10-035-14.[3] The UAE application sought a deferred accounting order to preserve the ability of parties to argue for or against the use of deferred REC revenue as a credit to ratepayers in a future ratemaking

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[1] Docket No. 09-035-23, "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."

[2] RECs are tradable, non-tangible energy commodities in the United States that represent proof that a megawatt-hour of electricity was generated from an eligible renewable energy resource. RECs can be sold and traded or bartered, and the owner of the REC can claim to have purchased renewable energy.

[3] Docket No. 10-035-14, "In the Matter of the Application of the Utah Association of Energy Users for a Deferred Accounting Order Directing Rocky Mountain Power to Defer Incremental REC Revenue for Later Ratemaking Treatment."

proceeding. On March 9, 2010, the Commission issued notices in both this, and Docket No. 10-035-14, setting scheduling conferences for March 16, 2010. The parties met at the scheduling conference on March 16 and discussed issues relating to these dockets.

On May 5, 2010, various parties filed a stipulation and joint motion for deferred accounting orders requesting the Commission grant the Company motion and UAE application to establish net power cost and REC revenue deferred accounting orders, respectively. The stipulation specified the parties' intention that the requested accounting orders create no presumption regarding future ratemaking treatment of the deferred amounts.

On June 7, 2010, the Commission issued a scheduling order for examination of the Phase II issues. This order called for three sets of hearings. First, the Commission would consider the parties' stipulation and joint motion for deferred accounting orders. Next, in Phase II, part 1, the Commission would receive evidence on the ECAM-related implications of the Company's hedging practices and its reliance on market energy purchases. Third, in Phase II, part 2, the Commission would consider all remaining issues, in particular the design of the Company's proposed ECAM and other parties' proposed changes and alternatives.

On June 29, 2010, the Commission held a hearing on the deferred accounting stipulation. Most parties joined in the stipulation, and no party opposed it. On July 14, 2010, the Commission issued a report and order approving the stipulation and joint motion.

On August 17, 2010, the Commission held the hearing on the remaining Phase II, part 1, issues. In this hearing parties presented written direct, rebuttal and surrebuttal testimony distributed between June 29, 2010, and August 10, 2010, and cross-examined opposing witnesses.

On November 1 and 2, 2010, the Commission held the hearing on Phase II, part 2 issues. As with the previous hearings, parties presented written direct, rebuttal and surrebuttal testimony on the specified issues and cross-examined opposing witnesses. The parties filed concurrent briefs on December 16, 2010.

On February 9, 2011, UAE filed a request for the Commission to take administrative notice of a decision of the Wyoming Public Service Commission, dated February 4, 2011, in Docket No. 20000-368-EA-10. The decision pertains to the adoption by the Wyoming Commission of an energy cost adjustment mechanism for the Company. The request of UAE is granted.

II. BACKGROUND

With limited exceptions, the Commission sets rates for electric service only in general rate cases. In determining rates that are just and reasonable, the Commission evaluates, among other things, the public utility's revenue, expense and investment levels within a given test period in order to identify a rate that, in the words of the Utah Supreme Court "is projected as being adequate to cover costs and give the utility's shareholders a fair return on equity." *Utah Department of Business Regulation v. Public Service Commission,* 720 P. 2d 420, 420 (Utah 1986).

In recent years the Utah State Legislature has enacted several statutory adjustments affecting the process of ratemaking in general rate cases. These adjustments include: 1) changes to the definition of test periods used in determining just and reasonable rates, enacted in 2003 (*see Utah Code § 54-4-4 (3)*); 2) allowing pre-approval of certain resource acquisitions, enacted in 2005 (*see Utah Code § 54-17-101 et seq*.); and 3) providing an alternative process for cost recovery of major plant additions, enacted in 2009 (*see Utah Code § 54-7-13.4*). In addition to these changes, the Utah Legislature, in its 2009 session, allowed the Commission to authorize energy balancing accounts for electrical corporations, including the Company, under prescribed conditions.[4] *See Utah Code § 54-7-13.5* (hereinafter referred to as the "Energy Balancing Account statute").

The Company's proposed ECAM in this case is a type of energy balancing account, which is a ratemaking technique used in this, and other, jurisdictions to adjust rates outside of a general rate case process. The Company's proposed ECAM would constitute a significant modification to the ratemaking process for the Company. In Utah, public utilities are generally not permitted to adjust rates retroactively to compensate for unanticipated costs or unrealized revenues.

The concept of applying a balancing account to at least some categories of the Company's power costs is not without precedent, however. In 1979, the Commission established an energy balancing account to accommodate recovery of unstable fuel costs and other expenses and revenues "which the [Commission] felt were subject to rapid and unpredictable fluctuation." *Utah Department of Business Regulation v. Public Service*

[4] The statute permits, but does not require authorization of a compliant energy balancing account. It explicitly "does not create a presumption for or against" such an account. *See Utah Code § 54-7-13.5(5).*

Commission of Utah, 720 P.2d 420, 421 (Utah 1986)*; see also Report and Order,* Docket Nos. 78-035-21, 79-035-03, pp.14-17 (July 20, 1979*).* At the request of the Company, and with concurrence of the Division and other parties, this energy balancing account was suspended effective January 1, 1991, and was subsequently eliminated on October 19, 1993. *See Report and Order*, Docket No. 90-035-06, p.17 (December 7, 1990)*; Report and Order,* Docket No. 90-035-06, p. 5 (October 19, 1993).[5] The reasons for this action relate to changes in the structure of the Company, both its ownership and its assets, and market conditions existing at the time.

In approaching this application, the Commission is cognizant of its general powers and jurisdiction to supervise and regulate the Company conferred by Utah Code § 54-4-1, (statutory authority invoked by the Company in its application). Moreover, the Commission is also mindful of Utah Supreme Court decisions which place limits on the Commission's general powers. For example, in interpreting Section 54-4-1, the Court has stated that despite this section's broad language, "this statute has never been interpreted by this Court as conferring upon the Commission a limitless right to act as it sees fit. Explicit or clearly implied statutory authority for any regulatory action must exist." *See Mountain States Telephone and Telegraph Company v. Utah Pub. Serv. Comm'n.* 754 P.2d 928, 930 (Utah 1988). Regarding instances where explicit statutory authority exists, such as the subject matter of this application, the Court has recently stated:

> It is well established that the Commission has no inherent regulatory powers other than those expressly granted or clearly implied by statute. . . . When a specific power

[5] Docket No. 90-035-06, "In the Matter of the Investigation Into the Reasonableness of Allocation and the Rates and Charges for Utah Power and Light."

> is conferred by statute upon a . . . commission with limited powers, the powers are limited to such as are specifically mentioned. . . . Accordingly, to ensure that the administrative powers of the [Commission] are not overextended, any reasonable doubt of the existence of any power must be resolved against the exercise thereof.

Heber Light & Power Co. v. Utah Pub. Serv. Comm'n, 2010 UT 27, ¶17 (internal citations omitted).

The Energy Balancing Account statute expressly grants the Commission authority to implement an energy balancing account for the Company within the limits, and meeting the conditions, the statute specifies. In view of the Utah Supreme Court decisions referenced above, the Commission views this grant of authority as setting the bounds of its power to alter prospective ratemaking with respect to energy-related costs and revenues. Among the limits and conditions set forth in the Energy Balancing Account statute, pertinent to this matter, are the following:

1. The energy balancing account must pertain to some or all components of the Company's incurred actual power costs, including: a) fuel, b) purchased power, and c) wheeling expenses; as well as the sum of the foregoing costs less wholesale revenues. *See Utah Code § 54-7-13.5(1)(b).*
2. The Commission must find the energy balancing account is: a) in the public interest, b) for prudently-incurred costs, and c) implemented at the conclusion of a general rate case. *See Utah Code § 54-7-13.5(2)(b).*
3. The energy balancing account may not alter: a) the standard for cost recovery, or b) the Company's burden of proof. *See Utah Code § 54-7-13.5(2)(d).*

4. Revenues collected in excess of prudently incurred actual costs shall: a) be refunded as a bill surcredit to an electrical corporation's customers over a period to be specified by the Commission, and b) include a carrying charge. *See Utah Code § 54-7-13.5(2)(g).*

5. Prudently incurred actual costs in excess of revenues collected shall: a) be recovered as a bill surcharge over a period to be specified by the Commission, and b) include a carrying charge. *See Utah Code § 54-7-13.5(2)(h).*

6. All allowed energy balancing account costs and revenues shall remain in the account until charged or refunded to customers. *See Utah Code § 54-7-13.5(4)(a).*

7. The balance of an energy balancing account may not be transferred by the Company or used by the Commission to impute earnings or losses to the Company. *See Utah Code § 54-7-13.5(4)(b).*

Additionally, the statute notes a balancing account formed and maintained in accordance with its provisions "does not constitute impermissible retroactive ratemaking or single-issue ratemaking." *See Utah Code § 54-7-13.5(4)(c).*

Only by acting within the bounds of the Energy Balancing Account statute can the Commission be assured it is not violating the Court's general proscription of retroactive ratemaking and single-issue ratemaking. Accordingly, the Commission's consideration of the issues raised in this application, and its resulting report and order, are governed by the Energy Balancing Account statute.

III. COMPANY'S PROPOSAL

A. Energy Cost Adjustment Mechanism

The Company proposes a rate adjustment mechanism which allows the Company to collect or credit the difference between certain actual net power costs ("Actual NPC") incurred to serve Utah customers and certain base net power costs ("Base NPC") collected from Utah customers through rates set in general rate cases. In its ECAM, the Company proposes using all of the components of net power cost as traditionally defined by the Company in general rate cases and modeled by the Company's production dispatch model Generation and Regulation Initiative Decision Tool ("GRID"). Specifically, the Company defines Base NPC and Actual NPC, to include amounts typically booked to the following Federal Energy Regulatory Commission ("FERC") accounts:

Account 447 – Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID

Account 501 – Fuel, steam generation; excluding fuel handling, start up fuel/gas,[6] diesel fuel, residual disposal and other costs that are not modeled in GRID

Account 503 – Steam from other sources

Account 547 – Fuel, other generation

Account 555 – Purchased power, excluding BPA residential exchange credit pass-through if applicable

Account 565 – Transmission of electricity by others.

[6] Start up fuel is accounted for separate from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both Base NPC and Actual NPC.

In response to comments of the parties, the Company modified its proposal to include wheeling and REC revenues. While transmission wheeling revenues have always been considered in determining Utah's revenue requirement in a general rate case, the Company argues they are not as substantial, volatile, difficult to forecast or outside the control of the Company as the components it has traditionally defined as net power cost in a general rate case. Therefore, the reasons for including them in an ECAM are not as compelling to the Company.

The Company argues REC revenues should be included because they are: 1) large as demonstrated by their recent and significant increase; 2) dependent upon illiquid, volatile and non-transparent market prices and are therefore volatile and unpredictable; and 3) dependent on the actual level of generation from unpredictable renewable resources such as wind and hydro resources. In addition, sales to certain entities may also require bundling RECs with energy production that is intertwined in net power cost in order to comply with state-specific certification requirements. For these reasons the Company believes it would not be equitable to have a true-up mechanism for REC revenue without a true-up mechanism for net power cost.

Using the proposed components to determine Base NPC and Actual NPC, the calculation of the proposed ECAM rate is based on a three step process.

Step 1 – Determine Base Net Power Cost rates

The Company proposes to set Base NPC monthly rates in a general rate case whereby total Company monthly [normalized or forecasted] net power cost is divided by the monthly normalized megawatt-hour load used to determine the net power cost to express the costs on a per unit basis ("Base NPC rate"). The Company supports updating the Base NPC on a periodic basis, as needed.

Step 2 - Compare Actual to Base NPC

The Company proposes to determine the Actual NPC monthly rate by dividing total Company monthly adjusted Actual NPC by total Company actual retail load in megawatt hours to express the Actual NPC on a per unit basis ("Actual NPC rate"). Any differences between the Actual NPC rate and the Base NPC rate will be multiplied by actual Utah tariff monthly load in megawatt-hours and 100 percent of the product will be deferred in the balancing account. The Company argues 100 percent of the product must be included in the balancing account in order to meet the requirements of Utah Code §§ 54-7-13.5(2)(g) and (h).

Accordingly, the Company's proposal can be written as:

$$Deferral_{Utah,month} = \left(\frac{NPC_{System,month}^{Actual}}{MWh_{System,month}^{Actual,retail}} - \frac{NPC_{System,month}^{Base}}{MWh_{System,month}^{Base}} \right) \times MWh_{Utah,month}^{actual,tariff}$$

The monthly under- or over-recovery will accumulate in the balancing account and earn interest. In rebuttal testimony, the Company agreed with suggestions to use its long-term debt rate from its most recently approved cost of capital as a carrying charge. If the Commission adopts this proposal, the Company recommends the cost of long-term debt should be updated each time a new cost of capital is approved by the Commission.

The Company states it will make adjustments to Actual NPC as booked to be consistent with the Company's production dispatch model, to remove prior period accounting entries, and to include applicable Commission-adopted adjustments reflected in the most recent general rate case. However, the Company will not adjust Actual NPC for hydro conditions and forced outages because they give rise to the fluctuations the mechanism is designed to capture. Actual NPC will be subject to review by the Commission and other parties annually when the Company files its applications for recovery of the deferred balance.

Because the difference in the Actual NPC rate and the Base NPC rate is multiplied by Utah actual load, the Company contends its proposed ECAM includes the additional net power cost revenue due to Utah load growth, and no further load growth adjustment is necessary. The Company opposes including any additional non-net power cost retail revenue due to load growth as this would result in a mismatch between revenues and expenses.

Step 3 - Amortization of the ECAM Balance

On an annual basis, the cumulative deferred balance in the balancing account will be converted to a rate identified in a new Schedule 94, “Energy Cost Adjustment,” and expressed on a cents per kilowatt-hour (“kWh”) basis for projected Utah sales for the twelve months of the proposed ECAM recovery period. The Company proposes the Schedule 94 rate will collect from, or credit to, customers the accumulated balance over the subsequent year. Schedule 94 rates will be zero initially, until a deferred balance is accumulated in the account and the Company is authorized to collect this balance. The Company proposes applying Schedule 94 as an equal cents per kilowatt-hour rate, after adjusting for voltage level losses, for all tariff schedules except time-of-day Schedules 6A, 8, 9 and 9A.

For Schedules 6A, 8, 9 and 9A, the Company proposes to adjust the equal cents per kWh applicable to other non-time-of-day tariff schedules for voltage level losses and proportionately shape the rate to mirror the structure of the time-of-day base energy charges for these schedules. This will reflect separate on-peak and off-peak cents per kilowatt-hour Schedule 94 rates for the periods from May through September and for the periods from October through April. Since the proposed Schedule 94 rate is volumetric rather than a fixed charge, the Company maintains the rate for customers having seasonal usage would be applied proportionately to their usage. The Company argues this will minimize rate impacts on these customers by reflecting the time-of-day structure in the Schedule 94 rates applicable to these rate schedules.

The Company maintains its proposed rate spread is simple and will be easy to administer. Moreover, it will directly apply changes in net power cost to customers' energy charges which will send clear signals to customers of changes in energy costs. For special contract customers, the Company proposes the application of Schedule 94 be governed by the terms of the special contract.

The Company believes its proposed ECAM will provide ample incentives for it to manage Actual NPC prudently. Consequently, in the Company's view, any form of sharing between customers and shareholders of the deviation between Actual NPC and Base NPC, or pre-approved performance standards, as proposed by other parties in the case, are unnecessary. The Company argues any of the sharing proposals offered in this case would, in effect, disallow prudently-incurred costs.

The Company maintains there will be ample opportunities to review the prudence of its management decisions affecting Actual NPC. The Company offers as examples, enhanced auditing during the proposed ECAM reconciliation filings and associated prudence reviews, in addition to the numerous other avenues to examine the Company's decisions prospectively such as in the IRP process, resource acquisition proceedings, certification of public convenience and necessity proceedings, major plant addition cases and general rate cases. The Company proposes this issue can be addressed by providing parties sufficient time to conduct a prudence review and audit. This could be accomplished by allowing the proposed ECAM rates to go into effect on an interim basis subject to refund as proposed by the Company and supported by the Division.

B. Need for an ECAM

The Company argues its net power costs are large, volatile and largely outside the Company's control and therefore meet the necessary criteria for an ECAM. The Company testifies its net power cost is currently the single largest component, nearly one-third, of the Company's Utah revenue requirement. In testimony supporting the request for approval of an ECAM, the Company argues it has consistently spent more on net power cost to serve customers than it has recovered in rates. The Company states the magnitude of this difference has grown in recent years. This, the Company explains, is mostly because the current ratemaking process of normalizing net power cost does not account for the increased uncertainty and volatility of assumptions that are key drivers to actual net power cost.

The Company testifies the difference between normalized net power cost and actual net power cost is more pronounced in recent years primarily for two reasons: 1) increased price volatility in natural gas and electricity prices, and 2) the Company's increasing resource portfolio exposure to uncertainty and volatility. Further, the Company explains it has been dramatically affected by changes in hydro conditions and wind generation, as well as changes in retail load, market prices, third-party wheeling expenses and natural gas and coal fuel expenses resulting from the 2008 global economic downturn.

The Company states it depends on both the electricity and natural gas markets to balance its system and meet load requirements. Therefore fluctuations in these markets invariably impact the Company's Actual NPC. Further, coal expenses, which had been relatively stable, are affected by changes in commodity costs due to contract re-openers, and even captive mine costs may change significantly due to rapid changes in the costs of mining equipment and supplies. The Company also indicates the composition of its resource portfolio, while diversified, is shifting to wind and natural gas resources, both of which increase the volatility of net power cost due to the intermittent nature of wind resources and high volatility of wholesale natural gas and power market prices, respectively. The Company asserts the variability in the Company's load can also lead to significant changes in net power cost.

For all of the foregoing reasons, the Company claims its net power cost is now subject to a much higher degree of volatility than in the past. Given the current economic conditions, uncertainties regarding environmental legislation, and continued additions of natural gas and wind resources, the Company expects this volatility to continue. In order to provide the

Company with an opportunity to recover prudently-incurred net power cost, and to ensure that customers do not over pay, the Company requests the Commission approve its proposed ECAM.

The Company contends it has been prudent in the management of its net power cost. However, the Company argues the volatility of its net power cost is primarily related to factors beyond its control. In addition, although the Company has utilized forecast test periods in recent general rate cases, static test-period data cannot accurately reflect the volatility in net power cost the Company is currently experiencing. During a period of net power cost volatility, the Company maintains establishing a fixed level of net power cost in rates, through use of normalized, modeled net power cost, virtually ensures customers will either over pay or under pay the cost of the energy they are using.

The Company believes traditional regulation cannot always address every cost factor equitably and needs to be modified to maintain the balance between the utility's customers and shareholders. In addition, the Company contends ECAM-type mechanisms are the universally accepted standard for dealing with net power cost to assure that rates are just and reasonable. The Company asserts an ECAM would provide safeguards to customers and give the Company an opportunity to recover the net power cost that is prudently incurred to serve those customers. Further, paying for prudently incurred costs is part of the regulatory bargain and customers should pay the prudent costs companies incur to serve them – no more, no less. Under its current Utah ratemaking mechanism the Company maintains it does not have a reasonable opportunity to recover its actual, prudently incurred net power cost in Utah.

As evidence to support its arguments, the Company provides: 1) data showing changes to its resource portfolio over time; 2) calculations comparing net power cost in rates versus actual net power cost; 3) an example of the volatility in daily load changes; 4) data showing the volatility in natural gas and electricity wholesale prices; and 5) a stochastic analysis of its net power cost to show the limits of hedging activities with respect to managing net power cost volatility.

The Company provides a table comparing its 1992 resource portfolio with its 2009 resource portfolio, demonstrating its increased reliance on natural gas and wind resources. The table shows natural gas resources changing from 1 percent to 17 percent and wind resources changing from 0 percent to 10 percent of the Company's resource capacity. The Company also provides a table showing forecasted total-Company peak loads and resources from 2009 through 2018 to demonstrate planned changes to its resource portfolio to include a greater percentage of natural gas and wind resources.

The Company provides a bar chart in its supplemental direct testimony showing the annual magnitude of difference between actual total-Company net power cost and total-Company net power cost "in-rates"[7] for the time period 1990 through 2008 and argues this demonstrates the Company has consistently spent more on net power cost to serve its customers in Utah than it has recovered in rates.

In its rebuttal testimony, the Company provides two exhibits the first showing the Company's calculation of actual net power cost, net power cost "in-rates," and the magnitude of

[7] The chart erroneously labels the total Company "in-rates" portion as Utah's share (see Phase I Supplemental Direct Testimony of Gregory N. Duvall, Table 1, p.4 line 83).

the difference between these two calculations for each of six rate-effective periods occurring in Utah from January 1, 2002, through September 30, 2009. In this exhibit, the Company determines average actual total Company net power cost and average "in-rates" total-Company net power cost (both on a dollars per megawatt hour basis), and multiplies the difference between these two numbers by the Utah load in megawatt hours for the same rate-effective period to determine the Utah share.

The second exhibit displays, for the same rate effective periods mentioned above, the difference between the in-rates and actual price of natural gas, market purchases and market sales, and identifies and values the differences in the volume of natural gas and wind generation. The Company maintains this exhibit demonstrates each of these individual data elements has been uncertain and volatile over the last eight years, and are key drivers contributing to the differences between in-rates and actual net power cost.

As an example of load volatility, the Company states system-wide loads under normal temperatures for January 27, 2009, were predicted as of November 2008 to be 8,010 megawatts. However, due to the cold temperatures across the Company's service territories, the actual load was 8,524 megawatts—an uncontrollable increase in loads of 514 megawatts. In February, however, the picture was quite different since it was a milder month. On February 7, 2009, actual loads were 524 megawatts below expectation. The Company testifies system operators have to buy or sell power at prevailing market prices when either of these situations occurs. The Company asserts these transactions cannot be hedged ahead of time, and in addition will result in transaction costs associated with the bid/ask spread.

To demonstrate the volatility of wholesale power and natural gas markets, the Company provides price history data, from January 2005 through February 2009, for the day ahead spot natural gas prices at Henry Hub and Opal, along with the day ahead spot prices for wholesale electricity (heavy and light load hours) at the Mid-Columbia and Palo Verde trading hubs.

The Company provides a description of the market products it uses to balance its physical position (including index price physical, fixed price physical, and physical option products) and hedge its market price risk (including fixed for floating swap, floating for floating locational basis swap, financial option, and fixed price physical products).[8] While hedging activities can reduce the range of potential outcomes, the Company argues hedging instruments cannot eliminate the risks of uncertainty and volatility. Hedging instruments are generally available to mitigate the risk of uncertainty in the price of natural gas and wholesale power for a known net open position, but significant variations subsequently occur in the net open position through the actual period.

The Company maintains natural gas swaps are part of a comprehensive hedging program which has successfully reduced the risk of upward volatility in net power cost for the benefit of customers. The Company indicates the purpose of swaps is to avoid extreme upward volatility in natural gas prices. If swaps were eliminated, and the Company had to rely entirely on fixed price forward physical products, net power cost would be higher. In addition, credit

[8] The Company defines a “fixed for floating swap” as a financial transaction with no physical delivery of natural gas or electricity. The Company pays a fixed price for the product established at the time the transaction is consummated, and receives an index price of a specified market price index established at the time of settlement. With a “floating for floating locational basis,” the Company pays the index price at one location and is paid the index price at another location, both established at the time of settlement.

risk would be increased as a result of fewer trading counterparties, reduced liquidity and higher transaction costs (resulting from higher bid ask spreads). The Company maintains if everyone were confident natural gas prices would only decline in the future, it would make sense for the Company to stop both fixed price forward physical and financial swap hedges, relying instead solely on the spot market. However, the Company argues hedging theory recognizes no one can accurately predict the future, and it is prudent to hedge against the risk that prices will move substantially in an unfavorable direction.

To demonstrate the inability of hedges to address uncontrollable or volatile components of its net power cost, the Company performs a sensitivity study using its stochastic production cost simulation model. With this model the Company examines the stochastic risk of loads, forced outages, and hydro generation using its 2008 Integrated Resource Plan (“IRP”) preferred portfolio. For this study the Company produces two model runs. The Company produces one model run where loads, forced outages, and hydro generation input assumptions do not vary stochastically. In this run, the Company states it fully and perfectly hedges the risk associated with these stochastic variables. It then compares the cost of this portfolio with the cost of the portfolio base run where all stochastic variables, including forward electricity and commodity natural gas, are subject to random draws. The cost difference between the two runs reflects the stochastic risk associated only with loads, forced outages, and hydro generation.

Using 2012 as the study year, the Company states the portfolio stochastic cost, as measured by the average of 100 simulation outcomes, increased by $80 million due solely to the combined volatility of loads, forced outages, and hydro generation. Tail risk, which is defined for this sensitivity study as the average of the five highest-cost simulation outcomes, increased by $666 million. This study, the Company argues, demonstrates there are significant amounts of net power cost that cannot be controlled using hedges. The Company notes wind variability is not modeled in the Company's stochastic model.

The Company also asserts the absence of a fuel and purchased power adjustment mechanism increases the risks to earnings and cash flow caused by volatility in net power cost. This volatility can adversely impact the Company's access to capital and liquidity, to the detriment of the Company and its customers. Further, the Company argues the absence of an ECAM affects credit ratings which have been and will continue to be important for the Company's ability to access these capital markets on reasonable terms.

For example, in a Standard & Poors April 1, 2009, report, analysts noted "the absence of fuel and purchased power adjusters in Utah, Washington and Idaho is material for the Company" and that absence was listed as one of the weaknesses under the "Major Rating Factors." Conversely, under "strengths," the approval of a power cost adjustment mechanism in Wyoming was identified as one of the factors that "ha[s] improved the Company's exposure to fluctuations in natural gas and purchased power costs." Similarly, in a FitchRatings report from August 31, 2006, the adoption of a fuel-adjustment mechanism in Wyoming was listed as a constructive event in Fitch's Rating Outlook Rationale.

In addition, the Company believes the proposed ECAM should help moderate the amount of imputed debt and interest expense adjustments related to power purchase agreements that Standard & Poors makes to the Company's published financial results when determining their adjusted credit metrics. The Company may also be able to reduce the amount of back-up credit lines it needs to ensure it can continue to fund itself in the event of unforeseen market conditions. These back-up credit lines protect the Company from defaulting if it is unable to roll over maturing commercial paper with new notes because of shrinkage in the overall commercial paper market, or the Company's inability to access the commercial paper market because of company-specific events, such as substantial under recovery of net power cost.

The Company asserts it is not in the public interest to limit the level of market purchases included in its proposed ECAM, as some parties recommend. The Company notes market purchases and hedging are currently included in base net power cost and were found just and reasonable by the Commission. Further, the Company maintains it is not necessary to change its hedging strategy with the adoption of its proposed ECAM, nor should a thorough analysis of the Company's reliance on market purchases or its hedging program be a pre-condition for an ECAM. The Company argues hedging is more appropriately addressed in its IRP process. The Company compares the amount of certain market purchases in the summer months in its last general rate case with the level of market reliance in its 2008 IRP Update and claims this shows adopting an ECAM does not increase the risk of market reliance to customers since that risk is already built into existing rates.

The Company argues the symmetry of its proposed ECAM is a desirable feature and does not shift the risk of prudent acquisition and reasonable pricing from the Company to customers. The Company asserts adoption of an ECAM will not in any way absolve the Company of its responsibility to prudently acquire resources. The Company argues most of the states in which it provides service, and for which it conducts its resource planning, already have cost adjustment mechanisms in place. Adoption of an ECAM actually adds an additional venue for parties to raise questions about the Company's prudence if there is a basis to do so.

The Company also believes an ECAM will provide timely recovery of net power cost and help customers receive accurate information about the economic value of electricity in order to make efficient consumption decisions. The Company further states as carbon is priced, and as conservation and load management are increasingly relied on as alternatives to traditional generation resources, customers' ability to make responsive choices will help them save money, improve reliability, and help achieve environmental goals. The Company believes properly priced plant additions, over time, will be less volatile for customers than open market power purchases regardless of whether they are recovered through an ECAM or other mechanism. With an ECAM in place, customers would obtain immediate benefit because net power cost savings will flow through immediately. Since the Company is also allowed to recover the capital costs of a major plant addition pursuant to Utah Code § 54-7-13.4, another single-item style rate change, the two mechanisms together provide the proper matching of both the fixed and variable costs and benefits of any new generation resource with the prices customers pay.

The Company states placing uncontrollable, prudent, costs into an ECAM, will enable the Company to focus on issues the utility can and should control, such as its long run mix of resources, pricing, and service quality. In response to some parties' suggestion the proposed ECAM shifts the risks of weather, loads and near-term market volatility to customers which should result in a reduced return on equity, the Company maintains the matter should be addressed in the next general rate case.

C. Implementation Issues

The Company recommends the Commission approve the proposed ECAM as a pilot effective February 18, 2010, the date the Commission issued its Report and Order on Revenue Requirement in Docket No. 09-035-23. REC revenue should be included in the ECAM beginning essentially at the same time net power cost is included in the ECAM. In addition, the Company testifies it can add transmission wheeling revenue to the ECAM deferred account effective February 18, 2010.

The Company proposes that after the initial starting period, the ECAM year would run from October 1 of each year through September 30 of the next year. The Company would then file its proposed ECAM reconciliation and updated factors December 15 and the adjustment would become effective by February 15 of the following year. The first application addressing a deferred amount in the balancing account would be made December 15, 2010. The Company maintains it requires two and one half months following the close of the ECAM period to make an ECAM filing.

The Company believes establishing a defined period for updating the Base NPC can be deferred until a future time when the Company is not frequently filing rate cases. However, if a load growth adjustment is adopted, as some parties propose, the Company maintains it will be necessary to update load levels more often than once every three years.

Regarding the determination of Base NPC, the Company argues current rates have been set on the basis of the rolled-in cost allocation method plus one percent, therefore Utah customers have received some of the benefit of west-side hydro resources. In addition, the reserve carrying capability of the west-side hydro facilities is shared systemwide and therefore is not part of the hydro endowment. The Company asserts it is inappropriate for parties to argue for a rate change based on inter-jurisdictional allocations unless and until any amendments to the Revised Protocol are ratified by the Commission *(see Docket No. 02-035-04)*[9] or alternatively in the Company's next general rate case. It is also inappropriate for parties to urge retroactive changes in rates, an action which is forbidden except in two circumstances, namely for extraordinary and unforeseeable expenses or revenues and utility misconduct that results in utility over-earnings.

In summary and based on the foregoing, the Company testifies its proposed ECAM design is in the public interest because it is simple to understand and sets up a fair regulatory process.

IV. PARTIES' POSITIONS ON THE COMPANY'S PROPOSAL[10]

A. Need for the ECAM and the Public Interest

The Division, Office, UAE, UIEC, WRA, UCE, SLCAP, Nucor and Wal-Mart all provide either testimony or argument opposing the Company's application for approval of its

[9] Docket No. 02-035-04, "In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues."

[10] Some parties use the terms "energy balancing account" and "energy cost adjustment mechanism" interchangeably. Other parties use the term energy balancing account to discuss a general mechanism and energy cost adjustment mechanism or ECAM to refer to the Company's specific proposal.

proposed ECAM. All of these parties argue the proposed ECAM is not in the public interest because the Company's application is deficient for one or more of the following reasons.

1. Public Benefits are Inadequately Defined

Several parties argue the Company's ECAM proposal fails to adequately articulate how ratepayers will benefit from the mechanism. UIEC, Wal-Mart, and Nucor contend the proposed ECAM should not be adopted unless the Company can demonstrate the mechanism results in potential benefits to ratepayers that outweigh the costs incurred.

2. Burden of Proof is not Sustained

Several parties argue the Company must bear the burden of proof as to whether its proposed ECAM is in the public interest. The Office, UAE, UIEC, and Nucor contend the Company has failed to do so in this proceeding.

The Office recommends the Commission reject the Company's ECAM proposal because it has not met its evidentiary burden demonstrating the proposed ECAM is necessary and in the public interest. The Office believes a significant portion of the risk the Company alleges is uncontrollable may actually be manageable by timely acquiring rather than continuing to defer planned physical resources. The Office also disputes the Company's representation of historical differences between "in-rates" and actual net power cost. The Office argues the Company does not provide sufficient detail supporting its assertion of persistent under-recovery of net power cost and fails to show if forecasted net power cost deviations will be large or "asymmetric" in the future.

The Office contends the Company's actual net power cost values are not adjusted for differences between projected prices for natural gas and short-term electric purchases and sales, as modified by Commission order or stipulation, and actual "booked" Company prices in each year for which the resulting rates were in effect. The Office further argues the Company's net power cost values do not include revenue offsets or revenue adjustments due to Commission policy or prudence determinations, i.e., the revenue imputation for the SMUD contract.

The Office disputes the relevance of the Company's rebuttal calculation of historical differences between "in-rates" and actual net power cost and provides an alternative analysis by comparing forecasted, rather than "in rates," net power cost to actual net power cost. The Office testifies several proceedings were settled and no "in-rates" net power cost values were actually determined. The Office's analysis compares the Company's forecast of total Company net power cost (including adjustments to these forecasts from explicit settlements or orders) to the actual total Company net power cost in four dockets in which a forecasted test year was used.[11] This analysis shows periods of both under-collection and over-collection of net power cost. The Office argues forecasting error is the major factor accounting for the differences between actual net power cost and amounts reflected in rates and recommends the Company improve its forecasting.

[11] Docket Nos: 04-035-42, "In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," from April 2005 through March 2006; 06-035-21, "In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Service Schedules & Electric Service Regulations," from October 2006 through November 2007; 07-035-93, "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, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," from January through December 2008; and 08-035-38, "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," from January through September 2009.

UAE also disputes the Company's assertion of net power cost under-recovery. UAE testifies the Company did not "come up short" in its net power cost within the test period determined in the 07-035-93 docket. UAE also testifies the Company's net power cost under-recovery calculations do not account for the effects of rate case settlements or power purchases resulting from delays in the scheduled start-up of the Company's Lakeside plant in 2007.

The Division provides evidence which contradicts the Company's assertion of persistent net power cost under-recovery. In a confidential exhibit, the Division shows forecast net power cost exceeded actual net power cost for two of the five time periods evaluated.

3. Future Test Period Already Mitigates Under-recovery Risk

Parties argue the Company's justification for its proposed ECAM is tenuous because a forecasted test period is allowed under existing regulatory statute. UAE contends the need for a forecasted test year is further diminished considering the Company's aggressive hedging practices and frequent rate case filings.

UIEC argues as long as power cost rates are set using a forecasted test year, cost recovery through an energy balancing account will only encourage the Company to set ever increasing forecasted power costs in general rate cases, leading to cost recovery gamesmanship. According to UIEC, the Company may estimate higher than actual costs and over-collect in the first (base) year. It can then refund to customers the excessive revenue collected during the second year. UIEC argues it is possible the Company would ensure it receives more in rates than its actual power costs, thus always overcollecting by paying the refund from customer overcharges. In addition, UIEC argues customers will "never have the opportunity to understand the actual cost of the energy they consume" because any surcharge imposed on customers would reflect the difference between forecasted and actual costs.

4. Proposed ECAM Reduces Existing Incentives for Least Cost Planning, Expansion and Efficient Operation

The opposing parties contend a complete pass-through of all excess net power cost will significantly reduce the Company's incentives to efficiently manage its operational, fuel, and purchased power costs, as well as long-run system planning and expansion. Parties argue the proposed ECAM shifts price, resource portfolio, weather-related, and forced-outage risks from shareholders to customers. In the current regulatory environment, Company management and shareholders incur the risk attendant to power cost fluctuations between general rate cases, and as a result have an economic incentive to actively manage net power cost risk through various cost control measures when planning and operating the system. Parties oppose any energy balancing account design that removes this incentive entirely.

For example, UAE testifies the Company made over 22 million megawatt hours of long-term, intermediate term, and short-term sales in 2009, conducted in over 150 transactions and argues the Company must have the proper incentives for these transactions to produce the greatest possible net benefit to customers. UAE argues this incentive is most efficiently implemented when the Company significantly shares in the benefits and risks of its decisions.

From an operational perspective, UAE argues, the Company has an incentive to avoid outages when replacement power is likely to be most expensive. Absent an ECAM, UAE notes the benefits and costs of deviations from net power cost in rates are absorbed by the Company. However, UAE asserts the proposed ECAM, which passes through 100 percent of net power cost deviations to customers, removes the Company's natural economic incentive to properly consider the impact on net power cost in its operations.

The Office, WRA, UCE and SLCAP maintain the proposed ECAM will impose the full risk of fluctuating prices on those who have the least ability to manage the risk. These parties argue this is inequitable, particularly if such a shift results in greater costs and risks over time.

Several parties argue the proposed ECAM will result in a resource portfolio biased toward market purchases and natural gas resources. WRA and UCE argue the proposed ECAM reduces the Company's incentive to invest in resources with low or zero fuel costs. WRA testifies this shift would be at the expense of renewable resources and energy efficiency measures and the long-run benefits these resources provide to customers. WRA argues this would result in the acquisition of "environmentally inferior" resources with significantly higher and more volatile long-run, risk-adjusted power costs to customers and a lower ratio of capital to operating costs.

5. Shareholder Risks are Reduced without a Rate of Return Correction

The Division, the Office, UAE, UIEC, WRA, UCE, and Nucor argue adoption of an ECAM reduces Company shareholder risk. The Office, UAE, UIEC, WRA, UCE, Wal-Mart and Nucor assert the Company should receive a lower authorized return on equity than it would otherwise obtain.

According to Nucor, "The consideration of fuel and purchased power costs outside of a general rate case [ignores] the negotiated level of risk compensation that the

Company currently receives through its authorized return on equity for fuel and purchased power price risk, weather-related risks, or outage-related risks." Nucor further argues "Because the Company has not provided any evidence that the shift in risk allocation would benefit customers, including any changes to the current ROE, the proposed ECAM has not met the fundamental 'public interest' threshold."[12]

UAE argues parties should address how such a reduction should best be measured and reflected in the next ratemaking proceeding. Wal-Mart specifies a return on equity reduction is a necessary condition for approval of an ECAM.

6. The Exclusive Reliance on Prudence Review is Inadequate

Most parties oppose the Company's proposal to rely completely on after-the-fact prudence reviews for ECAM reconciliation. Parties express concern that after-the-fact prudence reviews are difficult, costly, and are ineffective as a stand-alone incentive for the Company to control relevant power cost components under an ECAM. The parties argue when a company's financial performance is at stake, it has a greater self-interest in controlling costs and managing its operations and that audit-based third-party prudence reviews are an inferior means of evaluating performance.

The Division, the Office, UAE, UIEC, WRA, UCE, and Nucor, all testify the depth, breadth, and complexity of Company operations involving power costs are so extensive it would be an overwhelming task for regulators to conduct a thorough and complete audit of all the relevant decisions associated with the Company's procurement of fuel and purchased power,

[12] Nucor Phase II Post-Hearing Brief, December 16, 2010, p. 8.

the operation and maintenance of its generation resources, and all other factors influencing the occurrence of relevant power costs. The Division, UAE, UIEC, and Nucor note the potential auditing cost will be substantial for all parties and will require additional resources to account for approximately one-half of a million transactions.

The Division expresses concern regarding its ability to effectively perform adequate audits given its current workload and staffing levels. The Division notes the increased staff time required for the audits is problematic; further, it may not be physically possible to conduct the required audit of transactions in the time spans contemplated in the Company's filings.

UAE notes the depth and breadth of required dispatch and balancing activities are so extensive regulators cannot safely rely solely on after-the-fact prudence audits to ensure sound utility cost-management. UIEC testifies the Company engaged in 25,000 electrical financial and physical purchase and sales transactions and nearly 700 gas physical and financial transactions between January 1 and September 23, 2010, and the Company was expected to complete approximately 350,000 third-party wheeling reservations in 2010. Nucor argues a thorough review of such activities would be "staggering" for auditors. Further, Nucor argues even if auditors were to discover imprudent transactions, it is unclear "what number of transactions would create a material case for 'imprudence' under Utah Code § 54-7-13.5(2)(b)"[13] and states it would not be clear if such imprudence would be disallowed. Similarly, UIEC argues the Company's ECAM proposal does not provide procedures, standards or guidelines

[13] Nucor Phase II Post-Hearing Brief, December 16, 2010, p. 5.

upon which regulators would be able to conduct a prudence review and to make an accurate determination if the costs it is reviewing within the audit were prudently incurred.

7. Incorrect Accounts are Included in the Proposed ECAM

UIEC opposes the proposed ECAM because it shifts various costs and risks that are not authorized by statute. UIEC argues the Energy Balancing Account statute allows only the actual cost components of fuel, purchased power, and wheeling. Thus, costs not associated with physical commodities, or for wheeling in the delivery of power, specifically, costs related to financial products, resource availability, changes in load, or effects of political events, are not allowed by statute and therefore the proposed ECAM should be rejected.

For example, UIEC contends the Company's proposed ECAM includes fuel and purchased power costs associated with replacement power when the Company's generation resources are unavailable. UIEC claims this represents the assumption of additional risk not previously borne by customers if the energy acquired to replace lost power is greater than the Company's average production costs. UIEC argues any costs associated with resource unavailability beyond established benchmarks should be borne entirely by the Company. Unavailability risks, according to UIEC, are not contemplated or allowed within the statute.

UIEC argues the Company's ECAM proposal does not remove the capacity costs implicit in purchased power. Seasonal purchases include a capacity cost recovery component to pay the selling generator for its capacity. According to UIEC, a method to back out the capacity charges from purchased power costs must be developed so these costs do not flow through the energy balancing account. Otherwise customers could be paying twice for this capacity, i.e., once for the fixed costs of an idle Company generator, and again for the demand component of purchased power to replace the idling generator.

8. The Proposed ECAM is Inconsistent with Cost Allocation Factors

Several parties express concern the Company's proposed ECAM ignores long-standing principals of cost causation, sends the wrong price signals, and ultimately results in unjust and unreasonable rates because the rates bear no relationship to the costs of serving the customer classes. These parties argue the proposed ECAM fails to assign or allocate costs in a way that corresponds with actual usage and cost causation.

UIEC argues the Company's proposal to allocate ECAM costs does not result in just and reasonable rates because it ignores issues such as time of use and seasonality of the costs it proposes to recover through the ECAM, disregarding the varying responsibility of customer classes for consumption in individual months. In addition, the proposed ECAM results in a mismatch between cost allocation in base rates and allocation of costs recovered through the balancing account.

According to UIEC, the Company proposes to track deviations from base power costs on a "per kWh" basis. However, UIEC argues some of the proposed ECAM's power cost elements are allocated in base rates on a 75 percent demand, 25 percent energy basis. For example, while fuel costs are substantially allocated on a kWh basis, power purchases, power sales and wheeling expense are allocated on a 75 percent demand, 25 percent energy basis. UIEC claims this inconsistency creates a mismatch that could result in a cost allocation that "grossly skews" the relationship between cost causation and cost recovery, resulting in rates that are neither just nor reasonable.

Further, UIEC argues the Company's proposal does not track the seasonality of cost causation, and this could have a significant impact on rates. Based on the cost-of-service study for the 12 months ending June, 2010, Schedule 9 is responsible for 14.4 percent of the excess power costs incurred during the month of July. Thus, if the Company were to allocate its Schedule 94 surcharge monthly, Schedule 9 would get 14.4 percent of the excess power costs incurred in July. By summing monthly excess power costs and setting the surcharge based on the annual total, the seasonality is lost. Schedule 9 customers who caused 14.4 percent of excess power costs in July would receive a surcharge of 16.6 percent, which would apply not only to their July bill, but also to their bill in every other month of the year. By totaling the monthly deviations into one annual sum and then spreading the result across base rates as a surcharge on all consumption in every month and season, the Company has effectively negated time-of-use and seasonal rates for all costs recovered through its proposed ECAM.

Nucor also argues the Company's proposed ECAM does not reflect actual usage and unfairly penalizes users of off-peak energy. Nucor contends this is a significant omission, particularly considering customer classes do not equally cause the higher energy usage during summer and winter months when marginal generation and purchased power costs are high. Industrial and manufacturing classes that maintain more consistent load factors regardless of season do not drive summer and winter peaks and the associated higher energy costs. Nucor asserts Utah Code §§ 54-7-13.5(2)(g-h) outlines the standard for tracking costs and revenues in an energy balancing account. Nucor argues the Company's proposed ECAM, by contrast, does not have a collection mechanism that accounts for the wide variance in monthly or seasonal energy cost margins.

All parties oppose the Company's proposed use of the inter-jurisdictional cost allocation methods identified in the multi-state process ("MSP") stipulation which was conditionally approved in Docket No. 02-035-04. The Company proposes implementing its ECAM proposal on February 18, 2011, relying on Base NPC from Docket No. 09-035-23. Utah's revenue requirement in that case was set using the MSP stipulation mechanisms. Most parties argue the use of the MSP stipulation mechanisms to determine Base NPC will expose Utah customers to costs associated with the variability of system hydro resources without a commensurate share of the hydro system benefits. The parties argue this results in a mismatch in the allocation of costs between general and pass-through rates, and produces an unfair result for Utah ratepayers.

UAE contends the premium currently paid by Utah customers in the form of the MSP rate mitigation cap is entirely attributable to removal of substantial net benefits of the Company's hydro system from Utah's allocation of system costs. The proposed ECAM passes any increase or decrease in costs associated with deviations from a normal water year to Utah customers without the commensurate benefit of the hydro resources.

9. Proposed ECAM Provides Poor Price Signals to Customers

The Division, the Office, UIEC, SLCAP, and Wal-Mart all testify the proposed ECAM does not provide good or timely price signals to customers. These parties note prices actually paid by customers may be deferred up to one year under the proposed ECAM recovery mechanism, and therefore the price signal may bear little relationship to the real costs of current consumption. The parties argue such delays will result in potentially inaccurate price signals, may promote inefficient and wasteful use of energy, and may also hinder customers' ability to manage or mitigate net power cost risks and volatility. Wal-mart believes this is a fatal flaw in the Company's proposed ECAM design because the Company's current net power cost rates represent a large portion of the total bill received by customers.

UIEC testifies the proposed ECAM surcharge would result in rates unrelated to the costs the Company incurs in providing service at any given time. Further, the Company has not shown how to allocate the excess fuel and purchased power costs to the customers or classes of customers who cause the excess costs. For example, Nucor argues customers who currently limit exposure to price risks through efficiency or peak load curtailment would not have any more ability than they currently have to affect the Company's hourly decisions that impact the price of power. UIEC similarly argues the proposed ECAM mechanism does not reflect time of use or seasonality in a way that gives customers any information about the incremental cost of the electricity.

B. Recommended Design Modifications

Opposing parties recommend the following design modifications to the Company's proposed ECAM to ensure the public interest is served.

1. Require Risk Sharing

Parties argue if an ECAM is implemented it must include a sharing mechanism to restore the economic incentives that promote optimal planning, expansion and efficient operation that would otherwise be lost if all excess net power cost were passed on to customers. Parties argue sharing mechanisms increase the incentive for prudent utility behavior above and beyond after-the-fact prudence reviews.

The Division, the Office, UAE, and WRA all provide testimony arguing adoption of an ECAM in Utah without a sharing mechanism would not be in the public interest. These parties recommend some variant of a sharing mechanism that includes a 70 percent – 30 percent cost sharing mechanism in the ECAM design. Basically, under this level of sharing, the Company would bear the risk or earn the reward for 30 percent of net power cost that is higher or lower, respectively, than the amount in base rates (“70-30 sharing”). UIEC contends the Energy Balancing Account statute allows sharing in determining the components of an energy balancing account.

The Division’s proposed energy balancing account mechanism includes a 70-30 sharing provision with additional components. It incorporates a “dead band” whereby the Company bears all risk for plus or minus 2 percent of the relevant power costs that are “in rates” and the 70-30 sharing applies outside the dead band range. The Division argues this will help ensure the Company has adequate interest to keep the net power cost near the net power cost amount used to set rates. Further, the dead band provides the Company and its stockholders with some risk which helps justify the Company’s relatively high authorized return on equity and mitigates the need for ad hoc adjustments to this authorized rate of return.

The Division also proposes an outer limit for the sharing band at 30 percent above or below the difference from base net power cost. The Division argues this would give the

Company additional protection from potentially catastrophic changes in net power cost, or alternatively, fully benefit ratepayers from significant declines in costs beyond 30 percent.

The Division's proposal also provides for increased customer cost sharing if the Company meets specific goals regarding hedging and market purchases. If the Company meets the Division's proposed targets, it may apply for an increase in the customer sharing percentage from 70 to 80 percent in 2015 and from 80 to 90 percent in 2020.

The Office also recommends the Commission adopt a symmetrical 70-30 sharing mechanism if the Commission approves an ECAM. The Office testifies it would be important to ensure the Company retains significant interest in the costs that would be passed through to customers. With an ECAM in place, the Office argues the Company needs to have a significant monetary stake in net power cost outcomes to ensure management makes investment, operational and maintenance decisions that benefit ratepayers.

Parties argue the 70-30 sharing gives the Company enough economic self-interest to influence continued concerted efforts to prudently lower costs and reduce risks. In addition, UAE maintains the 70-30 sharing "establishes a reasonable threshold of materiality to ensure sufficient management incentive to control costs. As well as to take into consideration the magnitude of change that is reasonable if Utah is to migrate from the status quo, in which the sharing weight is effectively 0 percent customer and 100 percent Rocky Mountain Power."[14] UAE also contends this level of sharing is similar to the sharing provisions agreed to by the Company in Wyoming in 2006.

[14] Transcript, Phase II, Volume II, Testimony of Kevin Higgins, page 506, lines 10-17.

UAE disagrees with the Company's argument a sharing mechanism would potentially deprive the Company of the recovery of prudently-incurred costs and result in rates that are not just and reasonable. UAE argues proper ratemaking is not a matter of simple cost reimbursement. "Rather, rates are established in a general rate case at a level that provides the utility a reasonable opportunity to earn its authorized return and to recover prudently-incurred costs, including NPC, based on test period parameters. However, once rates are set, except for certain extraordinary circumstances that may give rise to deferred accounting treatment, the utility is expected to operate within the framework of those approved rates, and its management is expected to cope with normal business risks and the operation of economic forces. Failure of a utility to achieve the authorized earnings does not constitute a disallowance of prudently-incurred costs."[15]

Further, UAE maintains an imprudence finding following an after-the-fact audit is not a good substitute for the Company having "skin in the game" when it comes to managing net power cost. While imprudence requires a determination the Company acted unreasonably, a risk-sharing mechanism is structured such that each and every power cost action undertaken by the Company affects its bottom line and "provides an incentive for the Company to get the best possible result from every action taken." UAE contends trying to get the best possible result is a more exacting and efficient aspiration than behaving unreasonably and not getting caught. A well-crafted sharing mechanism allows the Commission to harness the natural economic self-

[15] UAE Exhibit 1D-SR, Surrebuttal Testimony of Kevin C. Higgins, Docket No. 09-035-15, Phase II, lines 33-42.

interest of the Company to promote desired behavior of ensuring sound utility cost management performance.

UAE opposes the Division's proposal to increase the sharing percentage assigned to customers to 80 percent by 2015, and to 90 percent in 2020, if the Company meets certain additional conditions. UAE does not agree the fundamental design of the ECAM sharing percentage should be modified to increase customer risk. The sharing percentage should reflect the need for the Company to have strong incentives to perform efficiently and to minimize fuel and purchase power expenses, subject to reliability constraints and risk management objectives. Also, the Division's proposal for adjustments to the sharing percentages in 2015 and 2020, appears fundamentally incompatible with the Division's core proposal that any ECAM be structured as a four-year pilot program.

While UIEC believes an ECAM with a sharing percentage is preferable to an ECAM without a sharing percentage, it argues there should be limitations. Sharing can operate in both directions from the base net power cost and is generally blind to the reasons for the departures. Unless audits detect imprudent behavior and result in disallowance, customers have no other protection. At a minimum, if an ECAM is approved, the sharing percentages should be coupled with performance standards, where the Company has to explicitly justify any performance that is sub-standard, such as the output of coal units, performance of wind resources and the output of coal mines.

WRA and UCE also propose a 70-30 sharing mechanism to counteract the proposed ECAM's potential disincentive to manage, control, and reduce net power cost. These parties contend the Company has the ability to manage several aspects of net power cost, and thereby has the ability to incur both prudent and imprudent costs through the consequences of its discretion. A 70-30 sharing mechanism provides an important incentive for the Company to control net power cost and a direct financial incentive to promote operational efficiency, by requiring the Company to continue to bear some share of the risk, whereas a prudence review is less likely to be effective.

2. Pre-approve Hedging Strategy or Exclude These Costs

The Division recommends study of the Company's hedging practices, for example in Docket No. 09-035-21.[16] If warranted after proper study, the Commission should approve a hedging plan for the Company. After the Commission-approved hedging plan is successfully implemented and the Company also has reached established goals for market purchases, the Division proposes the Company may seek an increase in the sharing percentage, as discussed above. The Division believes a key part of the Company's hedging strategy is the relationship of natural gas swaps with electric swaps and the Company should explore separating these two types of swaps. The Division is concerned the Company's current hedging strategy has been conducted without scrutiny or approval of regulators and has not been explicitly determined to be in the best interest of the Company or ratepayers.

The Office argues no hedging costs should be included in the proposed ECAM design. Rather, the Company's hedging practices need to be reviewed, considered, and acted upon in processes outside of the ECAM design proceeding in order for the outcome to be in the

[16] Docket No. 09-035-21, "In the Matter of the Natural Gas Price Risk Management Policies and Procedures of Rocky Mountain Power."

public interest. The Office recommends the Commission initiate a comprehensive evaluation to determine how the Company's hedging practices reflect the risk tolerances and preferences of customers, prior to implementation of an ECAM.

The Office testifies the Company has committed to new wholesale sales during a period when gas and wind resources are being deferred, reliance on short-term market resources has sharply increased to meet load requirements, and the Basin sub-region is expected to be resource deficient. The Company's proposed ECAM stems from the Company's claim it has uncontrollable risks associated with fuel prices, wholesale electric prices and loads. The Office believes a significant portion of the risk the Company alleges as uncontrollable may actually be manageable by timely acquiring rather than continuing to defer planned physical resources.

UAE argues if the Commission decides to implement an ECAM, hedging issues should not be addressed through ECAM design. Rather, UAE argues such issues should be treated in the Company's IRP process or in rate case proceedings.

UIEC recommends guidelines for hedging be established prior to the approval of any ECAM. Without an ECAM, UIEC believes the Company is at risk for the actions it takes and costs incurred, above or below the prices set in the preceding rate case, and these costs are the responsibility of the Company's stockholders, not its customers. Under this rate making process, the performance of hedging policies does not directly affect customers. If an ECAM is established, the performance of hedging policies will affect customers because the ECAM will track actual costs as compared to costs established in the preceding rate case.

3. Pre-Approve or Limit Market Purchases

The Division is concerned with the Company's reliance on market purchases to cover much of its capacity deficiency. The Division proposes expanding the sharing band of its proposed energy balancing account mechanism if the Company meets certain criteria involving market purchases. This would provide an incentive to meet goals established in the Company's IRP for future market reliance.

The Office and WRA recommend analysis to determine if market purchases are justified for inclusion in an energy balancing account mechanism, and if so, whether limits should be placed on the total amount of market purchases allowed to flow through the balancing account. The Office argues this would require a focused proceeding, outside of the ECAM proceeding, to determine reasonable limits and to avoid imposing arbitrary restrictions. The Office recommends market purchases be excluded from an ECAM until sufficient analysis justifies the inclusion of these costs. WRA proposes the Commission limit the Company's use of the short-term wholesale power market to meet capacity requirements.

As with its position on hedging strategies, UAE argues market reliance issues should not be addressed through ECAM design. UAE argues such issues should be appropriately treated in the Company's IRP process or in rate case proceedings.

4. Establish Energy Efficiency and Renewable Resource Targets

WRA and UCE argue there is no specific ECAM design component that mitigates the planning and input bias created by an ECAM. WRA argues the proposed ECAM creates incentives in favor of market and natural gas resources and disincentives for renewable resources and energy efficiency programs. Therefore, if the Commission approves an ECAM, no matter the design, the Commission should establish risk mitigation measures, such as strengthened resource planning, or targets for energy efficiency and renewable energy. WRA and UCE contend such measures would ensure "energy efficiency and renewable energy—resources whose fuel-free attributes mitigate fuel and carbon risks and reduce net power cost—are not forsaken for fuel or purchased power."[17] According to WRA, such targets and limits would be consistent with the portfolio that best manages risk and uncertainty as determined through the Company's IRP process.

5. Establish Coal and Wind Plant and Coal Mining Performance Standards

If an energy balancing account is adopted, UIEC recommends the Commission include as part of the informational requirements, certain minimum performance standards for the Company's lowest cost resources—its coal generation plants, wind resources and output from Company-owned coal mines. According to UIEC, requiring performance standards provides greater assurance operating performance will not degrade under a regulatory environment that includes an energy balancing account. UIEC argues such guidelines would also provide a financial incentive for the Company to minimize relevant costs.

Under these guidelines, the Company's low cost resources, its coal fleet, generation from wind resources and output from Company-owned or controlled coal mines, should be subject to standards such as benchmarks related to historical performance. When the

[17] Post-Hearing Brief of Utah Clean Energy, page 2.

Company files its ECAM reconciliation, it would be required to establish it prudently operated, maintained, and managed these resources.

The Division believes UIEC's recommended performance standards represent an unnecessary, unwise, and unfair attempt to micro-manage the Company's operations. The Division believes its own ECAM proposal mitigates the incentive concerns UIEC and the Division have raised. The prudence issues of plant operation are best raised in a general rate case, if and when events and data suggest a problem.

The Office believes UIEC's proposal on performance targets is premature and may produce unintended consequences. For example, the Company could elect to run more expensive coal plants to meet performance targets during a year when relatively cheap hydro power is available or use excessive amounts of cost-of-service coal from its mines when market (spot) coal is less expensive. These kinds of decisions would not benefit Utah ratepayers.

WRA does not support the performance standards proposed by UIEC for several reasons. First, UIEC's approach adds a great deal of complexity to the ECAM mechanism. Not only are the performance targets somewhat arbitrary, but demonstrating non-performance resulting in excess costs would be very difficult to determine. Second, performance standards can create unintended consequences. For example, whether some of the performance targets can be met depend upon circumstances beyond the Company's control. The final concern is that the performance targets apply selectively to only a few resources: coal, coal mining, and wind. UIEC provides no explanation for excluding gas generation and purchases from the performance criteria, or any other power source. Instead of performance standards, a simple sharing mechanism, that puts the Company at risk for 30 percent of all of its power costs, does a better job of addressing the important goals of UIEC's performance targets.

6. Eliminate Swaps

UIEC believes the proposed ECAM does not meet the Energy Balancing Account statutory requirements for Commission approval of an energy balancing account because, in part, it recovers costs not authorized by the Utah Legislature. Utah Code § 54-7-13.5(1)(b) allows recovery through an energy balancing account of enumerated categories of costs. UIEC believes the statute unambiguously designates the kinds of costs that can be considered for recovery under an energy balancing account are fuel and purchased power and may include natural gas, coal, steam, biomass, other fuels, and also wheeling revenues and expenses.

UIEC explains the Company's natural gas purchasing strategy is to fix the total cost of its natural gas supply for some substantial period of time by using financial products ("derivatives") and then to buy physical products periodically at index prices. UIEC reports the Company uses derivatives exclusively in the form of fixed-for-floating swap transactions. UIEC maintains costs related to financial products, resource availability, changes in load, or effects of political events cannot be included in an energy balancing account. UIEC recommends the Commission find swaps are not a component of actual power costs because financial products are not for any physical commodity, or for the delivery of any commodity. Therefore, these are not costs which the Utah Legislature intended for recovery through an energy balancing account. If the costs for swaps are to be recovered at all, UIEC argues, it must be in a general rate case when all necessary information is available for analysis.

7. Include Wheeling Revenues

If the Commission approves an ECAM, the Office supports including both the variations in wheeling costs and revenues in the mechanism. This will ensure consistency of matching revenues and costs, and account for impacts associated with the Company's ongoing Gateway transmission expansion.

UIEC believes it is important to track wheeling revenue; however, it is not necessary to do so through an ECAM. This revenue could be deferred outside of an ECAM, in recognition of the difficulty of forecasting the level, and in light of the fact that the Company's customers are being asked to support the revenue requirement associated with transmission expansion through the single-issue ratemaking process. Failure to track and defer this revenue would result in a loss of these benefits to customers.

The Division does not include wheeling revenues in its proposed energy balancing account stating the treatment of these elements should be determined outside of the ECAM.

8. Exclude Some or All of REC Revenue

The Division excludes REC revenue from its proposed energy balancing account because treatment of these elements should be determined outside of the ECAM.

The Office proposes to include a portion of incremental REC revenue in the ECAM design because of recent concerns with accurately forecasting these revenues in base rates. The Office identifies two portions of incremental REC revenue: (1) the incremental REC revenue currently being accrued in the deferral account as a result of the Company's significant under-forecast of REC revenue included in base rates; and (2) the incremental REC revenue (positive or negative) that will accrue during any time period for which an ECAM is in place. It is this second, going-forward portion, the Office recommends for inclusion in the ECAM design.

UAE opposes the Company's proposal to include REC revenue in the proposed ECAM. UAE recommends the deferred accounting order for incremental REC revenue should not be addressed in this docket, but rather should be analyzed on its own merits as part of setting rates in the next rate case or other ratesetting proceeding. It is not necessary for an ECAM to be adopted, or for an ECAM that recognizes REC revenue to be adopted, in order to obtain a reasonable outcome for customers on REC revenues. Given the extraordinary, and unforeseeable, circumstances surrounding the surge in the Company's REC revenue prior to the conclusion of the last Utah rate case, incremental REC revenue should be credited to customers as an offset to rates, irrespective of whether an ECAM is approved.

UIEC, like UAE, argues REC revenue is different from fuel and purchased power expenses. UIEC argues REC revenue is an asset created as a result of investment in renewable projects. REC revenue is linked to renewable resource projects that have been justified using REC values as an offset to costs and have been supported by customer rates. Variations in fuel and market power prices, on the other hand, are simply changes in input prices. The value of REC revenue can fluctuate appreciably, as the recent history recited in UAE testimony has demonstrated. UIEC recommends capturing these variations for the benefit of customers, whether or not there is an energy balancing account. This could be done by establishing a tracking mechanism specifically for REC revenue.

WRA believes REC revenue, like SO2 revenue, is not specifically a net power cost component and therefore should not be included in an ECAM. REC revenue should be tracked and addressed in a rate case or other proceeding.

9. Adopt Rolled-in Inter-jurisdictional Cost Allocation Method

The Division, Office, UAE, UIEC and WRA recommend the Commission order use of the rolled-in inter-jurisdiction cost allocation method as a condition for implementing any ECAM. Parties argue this is necessary to remedy the mismatch of costs and benefits to Utah customers contained in the Company's proposed ECAM.

The Division recommends resolving the "hydro endowment" issue as a condition of implementing an ECAM and suggests the Commission order use of the "rolled-in" methodology for interstate allocation of the ECAM costs. Since Utah ratepayers are being asked to pay replacement power costs associated with hydro variability, the Office believes it is only fair and reasonable they receive the full benefit of relatively lower cost hydro resources in base rates. The Office states eliminating the MSP cap and determining revenue requirement using the rolled-in method would align the benefits and costs associated with the hydro system in both general and pass-through rates. UAE argues an interstate allocation methodology must be utilized that produces results for Utah equivalent to or better than rolled-in allocations. UIEC believes the adoption of the rolled-in cost allocation methodology for Utah is a prerequisite to adoption of any ECAM because of the undue risk that would be placed on Utah customers with hydro variations under a system-wide ECAM but with the current costing procedure. The jurisdictional allocation approach must first be moved to a rolled-in basis. WRA testifies use of a rolled-in allocation method will be necessary if the Commission approves an ECAM.

UAE and the Office also argue if an ECAM is made retroactive to any degree (i.e., if ECAM adjustments begin any time before the conclusion of the Company's next general rate case), the Commission should condition the approval by requiring the Company to adjust the ECAM balancing account with a credit to customers for the entire one percent "premium" over rolled-in rates currently embedded in Utah base rates. The Office testifies this amount is about $14 million. UAE argues this credit is necessary to maintain appropriate synchronization between Utah's exposure to hydro risk in the ECAM and the recognition of hydro benefits in Utah base rates.

10. Require Consistency Between Cost Causation and Cost Recovery

To address concerns regarding the Company's proposed allocation of the deferred ECAM balance to customers, the Division and UIEC offer suggestions. The Division believes cost-of-service issues should be presented and dealt with in a general rate case. The Division recommends the Company propose ECAM rates for the various customer classes at the time the Company requests recovery of the annual deferred balance. These rates should be based upon the most recently completed general rate case order. Parties could then put forward changes to the proposed rates or any other aspect of the proposed ECAM balance recovery for adjudication by the Commission.

UIEC maintains principles of cost recovery suggest, to the extent possible, customers who cause costs should be allocated those costs. Customer classes should be billed each month based on the class's monthly energy usage and contribution to peak. Costs recoverable through an energy balancing account should be no different. Any surcharge should reflect the behavior of the class. UIEC advocates costs should be accrued monthly by rate schedule (and special contracts), and allocated on a monthly basis, with deviations accumulated into the periods of summer, winter, and spring/fall, and reconciled in the subsequent corresponding calendar time period. One-off costs should be booked in the month incurred.

11. Remove Capacity Charges

UIEC argues, as noted earlier, capacity charges should be removed from any energy balancing account for consistency with the Energy Balancing Account statute. UIEC does not propose a method for accomplishing this task.

12. Adjust for Load Growth

The Division, Office, UAE, and UIEC propose adjustments to the ECAM mechanism for load growth to avoid over recovery of fixed costs. WRA supports a load growth adjustment mechanism.

The Division proposes an incremental revenue adjustment that reflects revenue margins associated with generation, transmission and distribution since the last rate case. The Division's method adjusts for load growth by calculating the ECAM balance using total Company net power cost offset by total Company retail revenue and then allocating Utah's share. This revenue offset avoids recovering twice for fixed costs.

The Company opposes the Division's load adjustment and argues it could lead to unintended consequences. For example, if loads in Oregon increased, Utah customers would receive a revenue credit in the ECAM calculation even if Utah's actual loads matched Utah's forecast loads included in rates. In response, the Division states its energy balancing mechanism could address this by looking at Utah-only costs and revenues.

UAE recommends the inclusion of a load growth adjustment factor which is multiplied by each megawatt hour of Utah load change that occurs relative to the test-period load used for setting rates in the most recent general rate case. The resulting product is then credited against the balancing account and is subject to the proposed 70-30 sharing. In determining the appropriate amount of any ECAM revenue requirement, the incremental margins attributable to load growth should be credited to customers as an offset. If the ECAM becomes effective before the conclusion of the next general rate case (i.e., Docket No. 10-035-124), UAE recommends the load growth adjustment factor be set equal to $27.86 per megawatt hour.

In response to the Company's concern a load growth adjustment penalizes utilities with significant capital investment programs, and violates the matching principle, UAE notes the Company is allowed to file for alternative cost recovery of major plant additions in Utah. The MPA filings allow the Company to recover many of the very costs the Company claims are left out of UAE's proposed load growth adjustment.

The Office testifies, with the implementation of an ECAM, variations in net power cost will be separately tracked and recovered from Utah ratepayers between general rate cases. In order to ensure ratepayers are not overcharged in rates passed through the balancing account, the ECAM design needs to recognize additional revenue contributions to incremental generation and transmission fixed costs (rate base) the Company receives from load growth beyond the time of the test period. The Office believes the matching of variations in loads (revenue), net power cost and the fixed costs of incremental generation and transmission plant has merit and should be considered as part of the Company's proposed ECAM.

UIEC argues there is a potential problem with the load growth adjustments proposed by the parties. Following a test year, if there were to be an economic downturn, or the weather was cooler than normal, the proposals of both the Division and UAE would cause ratepayers to compensate the Company for reductions in revenues. UIEC believes any load growth adjustment should only work to offset increases in costs tracked through the energy balancing account. As an alternative approach, UIEC suggests the Company must first demonstrate it has not earned its authorized return on equity (with normal regulatory adjustments) during the period of time the additional ECAM costs were incurred, in order to collect positive ECAM values from customers.

13. More Timely Recovery for Better Price Signals

Wal-Mart recommends the inclusion of more frequent and forward-looking net power cost updates in the Company's proposed ECAM mechanism to allow it to potentially better match the Company's expenses with rates charged to customers and attempt to minimize the deferred amounts charged to customers. Absent frequent and forward-looking net power cost updates, the Company's proposed ECAM, if adopted, would not provide sufficient customer benefit so as to warrant Commission approval. Without such adjustment, Wal-Mart contends the Company's proposed ECAM fails to deliver the customer benefits expected out of a fuel clause.

14. Establish Carrying Charge of Six Percent or the Cost of Long-term Debt

The Division and UAE recommend the ECAM balance bear interest at a cost approximately equal to the Company's most recently determined cost of long-term debt. In response, the Company does not object to this carrying charge providing it is updated each time a new cost of capital is approved by the Commission.

The Office, however, recommends applying a 6.0 percent simple [annual] interest rate to the monthly accruals in the ECAM account. An interest rate of 6.0 percent approximates the Company's current long-term debt rate of 5.98 percent, which was used to set the interest assessed on the REC revenue and net power cost deferred accounts in the stipulation recently approved by the Commission in Dockets 09-035-15 and 10-035-14. In addition, a simple interest rate of 6.0 percent is currently applied to accruals in Questar Gas's 191 Account.

C. Implementation Changes

1. Beginning Date

The Company recommends implementing the ECAM at the end of the 2009 General Rate Case (February 18, 2010), on a pilot basis. The Division proposes the ECAM begin January 1, 2011, with a true-up filing made about a year later.

Both UAE and UIEC argue an ECAM, if adopted, should not be implemented until the conclusion of the Company's next general rate case (which is currently under consideration in Docket No. 10-035-124). Both parties maintain, per the requirements of Utah Code § 54-7-13.5(2)(b)(iii), an energy balancing account can only be implemented "at the conclusion of a general rate case."

UAE maintains because the Company's proposed ECAM was not, and could not be, implemented at the conclusion of the last general rate case, the statute requires it be implemented only at the conclusion of the next general rate case. Any other interpretation would render meaningless the express statutory wording.

UIEC contends, while the Company may have intended its proposed ECAM would go into effect at the end of the 2009 General Rate Case, neither the Company, the parties, nor the regulators could have anticipated the complexity of the issues involved in developing the evidence in this ECAM docket. UIEC believes it was impossible to implement the proposed ECAM at the conclusion of the last general rate case for several reasons: 1) The ECAM docket had barely progressed through Phase I; 2) there had been no evidence presented in this docket on natural gas hedging or front office transactions, or on the Company's specific proposal; and, 3) the Commission's order was not of sufficient granularity and did not make the specific findings relevant to the implementation of an energy balancing account. UIEC states the 2011 rate case, now under consideration in Docket No. 10-035-124, will provide an opportunity for the Commission to consider and set costs consistent with the kinds of costs that the Commission might allow to flow through an energy balancing account.

2. Ongoing Filing Procedure

Several parties, including the Division, the Office and UAE, concur with the Company's proposal for monthly accrual and annual reconciliation of the deferred balance if the Commission approves an ECAM. The Office maintains a true-up of the account on an annual basis should even out the seasonality in monthly accrual amounts. Wal-Mart, however, disagrees arguing the Company's proposal denies customers the transparency in rates which is a major benefit of moving to a fuel clause. Parties also disagree with other aspects of the Company's proposal regarding filing dates, the review period, and reconciliation issues.

The Division disagrees with the Company's proposal for the ECAM year to run from October 1 through September 30 with a reconciliation filing on December 15 of each year. Rather, the Division recommends the ECAM begin January 1, 2011, with a true-up filing made after the completion of a calendar year. The Division believes this leaves a reasonable period of time for analysis prior to the establishment of interim ECAM "true-up" rates. The Division asserts the Company's proposal to file on or about December 15th each year is unacceptable because the time for auditing prior to the Company's planned implementation date is insufficient and prejudicial to respondents.

While UAE concurs with the Company's proposal for an annual measurement period for adjusting rates, it proposes no recommendation regarding the use of a particular calendar period. UAE suggests the Commission select a period that is most administratively convenient for the parties tasked with reviewing the Company's filing. If the Company's proposed October 1 through September 30 period is used, UAE notes the inaugural ECAM rate would be based on a partial-year ECAM balancing account.

UIEC proposes true-up filings should not be made on December 15 but rather should occur sometime in the middle of the calendar year. This allows the Company's FERC Form 1 filing and other such reports to be available to third parties. It also avoids the busy holiday season and accommodates a seasonal reconciliation approach.

3. Resetting Base Net Power Cost

One of the primary elements of the Division's energy balancing account proposal is the requirement the Company file a general rate case at least every three years. The Office agrees with the Division's proposal that the base level of net power cost be re-set at least every three years in a general rate case. UIEC recommends the Company should not be allowed to file a general rate case during the pilot period and, if an energy balancing account is permanently adopted, no more frequently than every three years. This is because major expenditures can be recovered through proceedings other than a general rate case. Wal-Mart suggests frequent, forward-looking net power cost updates would enable the Company to potentially better match its expenses and rates charged. It would also minimize the deferred amounts charged to customers.

4. Pilot Program

The Division proposes implementing the ECAM program as a four-year pilot program. After four years, the Company must file to continue or modify the ECAM. Parties could support or oppose the Company's filing based upon the experience of the four year program. From the Division's viewpoint, one major purpose of the pilot program is to test whether the Division has the resources to adequately audit the ECAM.

The Office believes an ECAM pilot program should not be undertaken until the Commission has made a public policy determination on the threshold issues of market reliance and hedging. However, if the Commission implements an ECAM, this represents a major policy change in the way net power cost is treated in setting rates. Consequently, it is reasonable for the ECAM to undergo a trial run to see if strong incentives remain for management to make optimal decisions in the areas of resource planning, investment and utility operations. If management incentives are found to be lacking under an ECAM and sub-optimal outcomes result, then modifications may be required to the ECAM design or the entire mechanism may need to be removed to protect ratepayer interests.

In addition, the Office notes the Company's resource deficit substantially increases in the 2012 – 2014 "bridging period," according to the Company's 2008 IRP Update. From a policy standpoint, the Office contends the ECAM should remain as a pilot until the first major resource is acquired in 2015. This will provide the Commission with experience of how the ECAM performs over a period when the Company plans to rely heavily on market transactions to serve capacity requirements.

If an ECAM is adopted, UIEC argues it should be designated as a pilot program for a specific period of time with a sunset provision and a requirement to re-justify its continued existence in its then-current or modified form. An energy balancing account would be a significant change in rate recovery methodology in Utah and should not be implemented without a trial period first. UAE believes a time-limited pilot program should be structured using a basic set of parameters throughout its term and should not contain provisions that call for basic parameter adjustments, at the end of, or even beyond, its term, as the Division is proposing. If the ECAM is adopted, and if there are compelling reasons to continue it beyond the term of the pilot, the basic design parameters of the ECAM can be addressed at that time.

5. Pending Deferred Net Power Cost Accounting Case

Contrary to the Company's position recommending the Commission include the net power cost deferrals in the ECAM, the Division recommends the net power cost amounts accrued under the deferred accounting order remain separate from the amounts accrued under an approved ECAM. This would allow any actual ECAM to begin with a "clean slate." The Division proposes the Commission determine the amortization of amounts accrued under the deferral order in the next general rate case.

UAE submits the proper ratemaking treatment of the deferred net power cost should not be determined in this docket because the Company failed to carry its burden of proof to demonstrate it is entitled to recover the deferred net power cost from customers retroactively. UAE contends deferred net power cost cannot properly be charged retroactively to customers absent a sufficient showing under Utah law that retroactive ratemaking is appropriate. UAE maintains none of the recognized Utah exceptions to the general prohibition against retroactive ratemaking justifies retroactive customer surcharges for deferred net power cost.

Additionally, UAE points out Utah Code § 54-7-13.5(4)(c) provides that an ECAM "formed and maintained in accordance with this section does not constitute impermissible retroactive or single-issue ratemaking. " The statute, however, also expressly requires an energy balancing account may become effective only if "implemented at the conclusion of a general rate case." Because the Company's proposed ECAM was not and could not have been implemented at the conclusion of the last general rate case, UAE argues the statute requires the ECAM to be implemented only at the conclusion of the next general rate case. Any other interpretation of the statutory language would render meaningless the express statutory wording.

6. Pending Deferred REC Revenue Accounting Case

UAE requests its application for a deferred accounting order for incremental revenues from sales of RECs in Docket No. 10-035-14 not be addressed in this docket. Rather, it should be analyzed on its own merits as part of setting rates in the next rate case or ratesetting proceeding as discussed earlier.

UIEC maintains the Commission should initiate a proceeding to investigate the true nature of the conditions surrounding the deferred REC revenues, make a determination of whether the exceptions to the rule against retroactive ratemaking apply, and if so, order a rate adjustment so ratepayers can receive these improperly collected revenues.

D. Auditing Requirements

1. Third Party Auditor should be Used.

In response to the Division's concerns about having sufficient staff to conduct the required audits for the proposed ECAM, UIEC recommends Company shareholders fund, and the Commission choose, a third party investigator to perform the auditing function. The Division testifies funding for either an independent auditor or for additional Division auditors would likely mitigate the Division's concerns but testifies it has no position on UIEC's proposal.

2. Establish An Auditing/Prudence Review Plan

UIEC recommends the Commission require the Company to identify issues and problems with high costs and under-performing resources when it makes the proposed monthly informational filings, as requested by the Division, so as to reduce the need for auditing. This would allow auditors to target their efforts on potential problem areas. Further, UIEC testifies detailed auditing standards and procedures must be developed before a specific ECAM design could be found to be in the public interest. In order to judge the potential efficacy of an audit regime it needs to be clear at what point a transaction or policy could be challenged for prudence. Also, in UIEC's view, the appropriate standard of review must be established.

3. Reporting

The Division suggests the need to develop filing requirements for the annual proceeding on cost recovery. Further, it suggests it will need to obtain monthly information from the Company on its net power cost so as not to fall behind.

V. DISCUSSION, FINDINGS AND CONCLUSIONS

In the case before us, we must determine an appropriate ratemaking treatment for the Company's net power cost going forward. The Company proposes we adopt a particular form of energy balancing account and abandon our current practice of relying solely on normalized net power cost established in a general rate case for setting rates. Based on the record, we find sufficient reasons for reconsidering our current practice. Further, the Energy Balancing Account statute provides us with an additional rate-setting mechanism for net power cost if it is in the public interest. However, we find the Company's ECAM proposal, as filed, is not in the public interest for the reasons described in the record and discussed below. Therefore, without modification, it does not meet the statutory requirements for our approval of an energy balancing account.

We conclude with certain modifications, an energy balancing account for the Company can be designed to mitigate the concerns raised by the parties, to serve the public interest, and to satisfy the Energy Balancing Account statute requirements. These modifications are based on the evidence in this case. Accordingly, this order defines and approves this energy balancing account to be implemented at the conclusion of the Company's pending general rate case.

We now describe this energy balancing account (hereinafter referred to as the "EBA") and provide our rationale for its approval by addressing the key issues raised in this docket as follows: 1) Need for a balancing account; 2) balancing account design requirements; 3) balancing account components; 4) balancing account calculation; 5) ratemaking; 6) implementation, and; 7) pilot program reporting and filing requirements.[18]

A. Need for a Balancing Account

In the early 1990s, at the request of the Company, we eliminated use of an energy balancing account and approved use of normalized power costs and revenues established in general rate cases to set rates. Throughout the 1990s, the Company relied on its relatively stable coal and hydro-based resource portfolio with surplus capacity to manage changes in loads, resources and market conditions. During this time, we used normalized net power costs based on historic test periods to provide a reasonable basis for matching costs to revenues and setting rates.

[18] We do not determine what, if any, adjustment to return on equity should result from the implementation of the EBA. We invite parties to present any recommendations on this issue in the Company's pending rate case.

We find the Company's current portfolio of resources, its current need for capacity expansion, and its increasing reliance on markets to manage hourly system changes are substantial departures from the conditions existing in the early 1990s. The Company provides uncontroverted testimony its existing resource base is inadequate to meet future demand for electricity. As in the 1980s, the Company is once again in a capacity expansion period and is exposed to under-earning due to regulatory lag. Further, the Company demonstrates its resource portfolio now includes, and is expected to continue to add, substantial amounts of natural gas and wind resources. The Company shows, and most parties generally concur, the prices of natural gas and wholesale market transactions, and the output of wind resources are volatile.

In this time of capacity expansion, the Company has requested, and we have granted, use of future test periods as a reasonable basis for matching costs to revenues and setting rates and thereby reducing the effect of regulatory lag on Company earnings. Future test periods necessitate the use of forecasts of net power cost. With the greater reliance on natural gas and wind resources, and greater reliance on the market to manage changes in loads and resources, the Company's net power cost is subject to greater underlying variability, making the financial consequences of forecast error more significant than before.

The Company provides persuasive evidence demonstrating the effects of the increasing magnitude of the volatility on its actual, systemwide net power cost. The Company demonstrates its ability to accurately forecast systemwide net power cost in future test periods, even one year ahead, is questionable. With the existing ratemaking treatment of net power cost, i.e., forecasts within future test periods, the Company has no incentive to understate its net power cost forecasts, yet the record shows several forecasts over the past five years have been understated. More importantly, whether over- or under-forecast, the magnitude of the variation between forecast and actual system net power cost is increasing.

We recognize a missed forecast or even several missed forecasts are not a basis for changing rates in between general rate cases, especially for a subset of costs and revenues.[19] Indeed, the magnitude, cause and consistency of the Company's missed forecasts is debated extensively in the record. It is also uncertain from the evidence in the record which cost components of the Company's operations it can control and which it cannot due to their interaction. However, the increasing magnitude of the difference between system forecast and actual net power cost and the underlying variability of these costs raise a concern regarding the Company's financial health and fair rates to customers going forward which we now have an opportunity to address.

In 2009, the legislature authorized a new regulatory mechanism specifically for power related costs and revenues with which we are able to set rates - provided we find it is in the public interest. We conclude this new mechanism, properly designed, can be targeted to mitigate potential financial harm to the Company and avoid unfair rates to customers resulting from setting rates through sole reliance on net power cost forecasts which do not adequately capture the underlying variability of the inputs to net power cost.

To serve the public interest and to ensure just and reasonable rates, most importantly this new mechanism must fairly allocate risk between customers and shareholders,

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[19] *See Utah Department of Business Regulation v. Public Service Commission of Utah*, 720 P.2d 420, 420 (Utah 1986), "To provide utilities with some incentive to operate efficiently, they are generally not permitted to adjust their rates retroactively to compensate for unanticipated costs or unrealized revenues."

maintain incentives to operate efficiently, both in the long-run and short-run, and satisfy the requirements of the Energy Balancing Account statute. Achieving these objectives is a complex endeavor due to many factors, including another recent statute which allows the Company to request rate changes outside of a general rate proceeding for major plant additions. Both the major plant addition and Energy Balancing Account statutes complicate the traditional ratemaking process of matching all costs and revenues over a given time period to determine just and reasonable rates. We therefore approve a balancing account on a pilot basis and apply the principle of gradualism as we design and implement this additional ratemaking mechanism.

B. Balancing Account Design Requirements

A primary objective in the design of an energy balancing account in the public interest is to ensure sufficient incentive for the Company to continue to make and implement prudent resource decisions to benefit customers going forward. The Company believes a regulatory review of the prudence of its net power cost decisions, with the potential for the disallowance of imprudently incurred costs, provides sufficient incentive for the Company. We agree that prudence reviews of net power cost in general rate cases and other applicable rate-setting proceedings remain an important feature of regulation.

Several parties, however, argue a prudence review alone is inadequate to align customer and shareholder interests when an energy balancing account is designed to pass all net power cost differences between forecasted and actual net power costs through to customers. Consequently, we are asked by several parties to establish predefined or pre-approved levels of hedging, market purchases, energy efficiency programs, renewable resources or low-cost resource operating characteristics. Parties recommend we do this either prior to any change in the ratemaking treatment of net power costs, or prior to approval of costs in any net power cost balancing account. This, parties argue, will ensure Company actions remain consistent with customer interests.

For example, parties question the composition of the Company's resource portfolio claiming the Commission must set resource-specific targets before relying on prudence reviews to discipline management behavior. Specifically, parties raise concern with the Company's long-run strategy of market reliance in the IRP process and in this record. However, no party has criticized this strategy in a rate setting proceeding which is the appropriate venue for judging the Company's decisions and determining whether costs are prudent and should be included in general rates.

Similarly, parties raise concern in this docket with the Company's use of physical and financial hedges to manage market reliance risk and assert the need for Commission-approved standards before an energy balancing account is established. Yet, no party contested the inclusion in rates of these costs in the Company's most recent general rate case, again, an appropriate venue for raising issues of prudence and cost disallowance. We conclude the Company's current portfolio of resources, including the reliance on markets, use of hedging instruments and wind and natural gas resources to the degree currently employed, has been examined in former proceedings and therefore is not the issue in this case.

While we recognize and agree with the parties' concerns about the need for incentives in addition to prudence reviews, we decline to adopt the proposals to establish standards or targets, or to set limits on components of power costs. First, we agree with the Division, rate change proceedings provide a better venue to examine data and make a determination on prudent levels of market reliance and use of other resources to serve the public interest. Second, setting pre-determined levels as suggested by the parties may impede the Company's flexibility to manage its resources wisely. As this record demonstrates, market conditions change and it is not our intention to micro-manage the Company's operations. Third, the record identifies a more effective means of providing the required incentives. Based on the recommendations of several parties, we conclude an EBA design which includes risk-sharing during regulatory lag, coupled with prudence review, is superior to predefined standards or pre-approved levels of hedging, market purchases, energy efficiency programs, renewable resources or low-cost resource operating characteristics.

As in the past, we will continue to rely on prudence reviews during rate setting proceedings to determine the extent to which the Company is providing least-cost, risk-adjusted service to its Utah customers, consistent with integrated resource planning and competitive solicitation analyses. We recognize, however, relying solely on prudence reviews will shift too much of the risk for suboptimal planning and operation currently borne by the Company, who is in the best position to manage this risk, to customers, who are not. Therefore, the balancing account we adopt requires both Company customers and shareholders to remain at risk for a portion of the actual net power cost which deviates from approved forecasts. This decision recognizes the value of Company management having meaningful financial incentives to minimize net power cost in the short-run and long-run, regardless of the extent of net power cost volatility. We find a sharing mechanism is the best method, at this point, to ensure customer and shareholder interests are aligned and the public interest is maintained.

Parties proposing risk sharing recommend, at a minimum, a 70-30 percentage sharing between customers and shareholders, respectively, of differences between the forecasted and actual net power cost which are subject to the balancing account mechanism. Based on the arguments presented in this case, we agree. We find this design component provides an appropriate sharing of risk for the pilot period based on the principle of gradualism, especially given the difficulty in identifying controllable and uncontrollable components of net power costs. Currently, when using forecasted net power costs to set rates, both customers and shareholders face 100 percent of the risk that actual costs will differ detrimentally and substantially from forecasted costs. This is a zero sum game, where all benefits flow to one group (customers or shareholders) at the expense of the other. A balancing account designed to include the 70-30 sharing component described above for the approved net power costs will dampen this risk and improve the fairness of outcome for both customers and shareholders. We will review this level of sharing at the conclusion of the pilot period to determine whether it continues to be reasonable.

We agree with UAE, in addition to the current ratemaking method, an EBA with sharing will improve the Company's opportunity to recover net power cost. Contrary to the Company's view, providing an improved opportunity to recover costs is not punitive. Also as noted by UAE, ratemaking is not simply cost reimbursement. Approved base rates provide a reasonable opportunity for full recovery of prudent test period costs, including a return on rate base. Failure of the Company to achieve its authorized return under current ratemaking practice does not constitute a disallowance of prudently-incurred costs. This will continue to be the case after the EBA is implemented.

We also agree with UAE, the Company is incorrect in suggesting the Energy Balancing Account statute prohibits a cost sharing component to the EBA design. Rather, the statute does not prescribe a particular design and is silent on the detailed operation of an energy balancing account. Further, it is not unusual for states to include cost-sharing features in energy balancing account mechanisms. For example, the Company's energy balancing accounts in Wyoming and Idaho have sharing elements. Finally, if the ratemaking process can properly assign 100 percent of the risk or benefit of net power cost deviations to the Company between rate cases, as has been the case for decades, it can now also properly assign 30 percent of such risk to the Company.

We decline to adopt the Division's dead band or other features associated with its proposed sharing mechanism. These adjustments add a level of complexity without sufficient benefit. We accept parties' proposal of a four-year pilot period. We will evaluate the level of sharing at the end of the pilot to determine its effectiveness in aligning Company and customer short-run and long-run interests. This sharing component will serve to provide a gradual change from current ratemaking practices, wherein all costs and revenues are evaluated over a consistent period of time to determine just and reasonable rates, and between rate cases the Company bears 100 percent of the risk that actual net power cost will be higher than forecast net power cost.

C. Balancing Account Components

We include the Company's recommended FERC accounts in the balancing account with the following changes. First, we are persuaded by UIEC, swap transactions should be excluded from the calculation of both base and actual net power cost. We agree swap transactions do not track well with the statutory definition of energy costs. Swap transactions currently approved will remain in base customer rates. We also conclude these transactions must be reviewed and approved in each general rate case, which is an appropriate proceeding for determining the prudence of Company decisions.

Second, we find it appropriate to include wholesale wheeling revenues, FERC account 456.1, in the balancing account calculation. Though not modeled through GRID, wheeling revenues have always formed an offset to wheeling expenses in general rates. To set power-related rates without recognition of this offsetting revenue would violate the matching principle.

We are not persuaded the revenue from RECs should be included in the balancing account. It is less directly related to net power costs as delineated in the Energy Balancing Account statute than, for example, wheeling revenues. It is more like SO2 allowance revenue. Additionally, REC revenues can be banked, which adds further complexity to their regulatory treatment. We conclude REC revenues are better addressed in a general rate proceeding or other appropriate filing. Consequently, we will treat the deferred REC revenues accruing pursuant to any future decision in Docket No. 10-035-14 in a separate proceeding.

UIEC expresses concern regarding the inclusion of capacity charges in the balancing account. However, the statute allows "power purchases" in the energy balancing account and does not make a distinction between non-firm (interruptible energy) and firm (seller guarantees availability) power purchases, the latter which is likely to be priced to recover some component of capacity cost. Further, neither UIEC nor any other party provides a method for implementing the EBA without including capacity charges in the power costs it captures. We direct the Company and Division to evaluate this issue further during the pilot period of the EBA to determine if it should be addressed differently in a permanent program.

We concur with all parties and require the EBA to capture incremental revenue for net power cost due to Utah load growth. We approve the structure of the Company's balancing account calculation which is expressed on a per unit basis and multiplied by actual Utah sales and therefore accomplishes this task. However, at this time, we are not persuaded to include in the EBA an adjustment to capture incremental revenue contributions for fixed costs due to load growth for several reasons. First, these revenue changes may not be directly related to the components included in the balancing account. Second, we are persuaded by testimony in this case of possible unintended consequences associated with implementing such a factor. Third, we conclude these adjustments are outside the scope of the statutory definition of costs to be included in the balancing account.

For clarification, we include wind integration costs in the calculation of base and actual net power cost. The Company testified its proposed ECAM would be calculated using all components of net power cost as traditionally defined in the Company's general rate cases "and modeled by the Company's dispatch model GRID." Although certain wind integration costs are not explicitly modeled through GRID, these costs appropriately belong in the EBA for a couple of reasons. First, customer rates include forecasted wind integration costs. If we exclude wind integration costs from base net power cost, actual wind integration costs would need to be deducted from actual net power cost which could be a difficult and controversial undertaking. Second, these costs are subject to the intermittent output of wind resources which is one of the sources of volatility underlying the Company's request for a balancing account.

D. Balancing Account Calculation

We concur with UIEC, the Company's balancing account calculation is inconsistent with Utah's allocated share of power-related costs and revenues and therefore contravenes cost causation and the setting of cost-based rates. The Company's calculation assumes all power-related expenses and revenues are allocated to Utah based on Utah's relative use of total-Company energy use. This allocation is inconsistent with approved allocation factors whether using rolled-in or revised protocol cost allocation methods or the MSP stipulation mechanisms. To ensure rates reflect cost causation and cost-based rates, the cornerstones of a just and reasonable rate, the balancing account must be based on Utah's approved factors for allocating total Company costs to the retail customers in Utah. Accordingly, the allocation factors approved in the pending general rate case, Docket No. 10-035-124, shall be used to determine Utah's allocated share of the power-related expenses and revenues approved for balancing account treatment.

Similarly, collection or refund of any EBA balance must also be based on cost of service. The Company's proposal to allocate the balance to customers based only on energy use and indiscriminately to all schedules, fails to fully consider our cost-of-service or revenue spread decisions and therefore would be unfair to customers, as we discuss in the next section. We also approve an annual carrying charge of 6 percent. As noted by the Office, this rate is consistent with the carrying charge rate approved for Questar Gas Company's gas balancing account. This rate is also similar to the Company's long-term cost of debt, the rate recommended by most parties.

Given the foregoing decisions, we approve a balancing account calculation which is similar in structure to the Company's proposed calculation but is altered to convey the use of Utah's allocated share of costs and revenues, Utah retail sales for megawatt hours, and the sharing design component, expressed as follows:

$$Deferral_{Utah,month} = 0.70 \times \left(\frac{NPC^{actual}_{Utah,month}}{MWh^{actual}_{Utah,month}} - \frac{NPC^{base}_{Utah,month}}{MWh^{base}_{Utah,month}} \right) \times MWh^{actual}_{Utah,month}$$

As indicated in the above expression, the deferral will be calculated each month to determine the amount to be accrued into the balancing account. To ensure appropriate billing units are available to calculate the monthly deferrals, and to comply with Utah Code § 54-7-13.5(2)(e)(i), all megawatt hours will be equal to Utah retail sales, from actual billing records and from the most recent general rate case as appropriate.

An annual interest rate of 6 percent (0.5 percent per month) will be applied to the average balance carried in the account each month calculated as follows:

$$Balance_{current\_month} = \left[Ending\_Balance_{previous\_month} + Deferral_{current\_month}\right]$$
$$+ \left[\left(Ending\_Balance_{previous\_month} + \left(Deferral_{current\_month} \times 0.5\right)\right) \times 0.005\right]$$

At the end of the twelve month period, and following a hearing on the prudence of the actual costs, the ending balance will yield "prudently incurred actual costs in excess of the revenues collected" to be recovered in rates through a surcharge to customers pursuant to Utah Code § 54-7-13.5(2)(g), or, "revenues collected in excess of prudently incurred actual costs" to be surcredited to customers pursuant to Utah Code § 54-7-13.5(2)(h).

E. Ratemaking

We concur with UIEC the Company's proposed Schedule 94 lacks specificity. We direct the Company to file a revised Schedule 94 for our approval which provides the equation for the balancing account noted above and itemizes each FERC account and subaccount approved for balancing account treatment, similar to the Questar Gas Company gas balancing account tariff. The description must also explain in detail the types of adjustments the Company intends to make to actual costs booked.

As noted earlier, collection or refund of any EBA balance must also be based on cost of service. Therefore, we will rely on our most recent general rate case revenue spread and rate design decisions for the spread of the deferred balance to rate schedules and to rate elements. For simplicity, we decline to adopt UIEC's proposal to account for the balance by rate schedule.

F. Implementation

Beginning Date: We approve implementation of this approved EBA on the first day of the month following our decision in the Company's pending general rate case, filed January 24, 2011, in Docket No. 10-035-124. The base net power cost used to determine the "revenues collected" for calculating the monthly deferred amounts will be determined based on the outcome of that case. We accept the Company's proposal for annual reconciliation of the deferred account balance. Annual reconciliation will allow for rate stability and simplicity. This 12-month period shall be a calendar year. However, the starting date for EBA accruals will coincide with the date rates are made effective in the pending rate case. Therefore the first reconciliation will be for a partial year. Base net power cost will be reset in appropriate rate change proceedings or as needed.

Ongoing Filing Date: We concur with the recommendation of the Company and Division to establish an interim rates process. We adopt a review process with hearing to set "interim rates." We direct the Company to file annually, on March 15, to collect or refund the calendar-year deferred balance. Following the Division's audit and a prudence review, we will set final rates.

Stipulation on Deferred Net Power Cost: We will address the ratemaking issues associated with the stipulation on deferred net power cost separately from this order. We will also consider the balancing account treatment for the one percent premium above Utah's rolled-in share of total system costs approved in the last general rate case in the course of the pending general rate case or other appropriate proceeding on the deferred net power cost balance. As to any deferred net power cost balance prior to the conclusion of the next general rate case, we will require use of the rolled-in allocation factors and appropriate treatment of the MSP stipulation mechanisms, unless the Company can demonstrate continued use of the MSP stipulation mechanisms is in the public interest. We directed parties in Docket No. 09-035-23 to address the propriety of using the MSP stipulation mechanisms approved in Docket No. 02-035-04 for setting rates in Utah prior to any further rate changes.[20] The request for recovery of any deferred net power cost balance requires this showing.

G. Pilot Program and Reporting and Filing Requirements

We order the implementation of the EBA as a 4-year pilot program. The start date of the pilot period is the first day of the month following our decision in the pending rate case, as noted above. In order to ensure the EBA is effectively implemented, we order the formation of an EBA working group to address the issues below. This working group shall be led by the Division and include all interested parties. The work group is directed to:

1) Develop a complete list of data, transactions and other information the Company will be required to file each March 15 to constitute a complete filing.

2) Identify monthly information to be provided to the Division for its ongoing review.

3) Develop a pilot program evaluation plan to:

[20] "...we intend to have inter-jurisdictional allocation issues addressed and the reasonableness of any allocation established prior to our approval of any future change in RMP's rates." November 9, 2009, Order Staying October 19, 2009, Order in Docket No. 09-035-23.

a) Identify data and information to be tracked and evaluations to be conducted during the pilot.
b) Identify training requirements, and conduct training for the work group, including, but not limited to:
   i) the relationship of accounts in the EBA to the net power components in the GRID model;
   ii) the relationship to FERC accounts and how they are booked and reconciled, i.e., Account 151 Fuel Stock and account 501 Fuel.

4) The pilot program shall evaluate, at a minimum:

a) The sharing mechanism;
b) which net power cost components are controllable and which are uncontrollable and whether the sharing element should be eliminated from the uncontrollable costs in the EBA;
c) the effects of the EBA on the Company's resource portfolio;
d) whether the EBA includes the appropriate net power cost components;
e) the effects of the EBA on the Company's hedging decisions and level of market reliance on net power cost;
f) parties' incremental costs to audit the balancing account;
g) unintended consequences resulting from the EBA; and,
h) monthly vs. annual accrual differences.

Items 1 through 3 shall be filed for our approval no later than 120 days from the date of this Report and Order.

We direct the Division to file a written preliminary evaluation of the pilot program per item 4, including the identification of issues or concerns with the program, within four months after the conclusion of the second calendar year of the pilot. We direct the Division to submit a final evaluation of the pilot program, per item 4, within four months after the conclusion of the third calendar year of the pilot. This pilot program evaluation will include the Division's recommendation as to whether the program should be continued as is, modified or discontinued.

H. Summary

Based upon the extensive record before us, we conclude the EBA we authorize in this Report and Order is in the public interest and will result in the setting of just and reasonable rates. This EBA, as well as other ratemaking proceedings that will continue to take place, will afford the Commission and parties adequate opportunities to evaluate the prudence of the Company's actions affecting net power cost levels, so that only prudently-incurred costs may be allowed in rates. The prudence of the applicable costs will continue to be examined in general rate cases and other appropriate rate-setting proceedings, and will now also be examined in annual EBA proceedings to set the balancing account rate. Moreover, the risk sharing aspect of the mechanism preserves the Company's financial incentive to minimize net power cost both in the short-run and long-run, consistent with sound policies and practices.

We also conclude the EBA we approve does not alter the standard of cost recovery we are bound to apply or the Company's burden to prove the reasonableness of the costs it seeks to recover in rates. The mechanism only pertains to actual net power cost and will be implemented, as the Energy Balancing Account statute requires, at the conclusion of a general rate case. That case will provide the forecast of net power cost that will serve as the initial baseline for the mechanism.

Finally, we conclude the EBA adopted herein will function in conformance with the structural requirements of the Energy Balancing Account statute. Excess costs and revenues will be treated consistent with the statute's provisions. In particular, the EBA balance will remain in the deferred account until charged or refunded to customers. Under no circumstances will any balance be transferrable by the Company or used by the Commission to impute earnings or losses to the Company.

VI. ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED, that:

1. Pursuant to the evidence of record, the application of PacifiCorp for approval of its proposed energy cost adjustment mechanism is approved as a pilot ratemaking program, subject to the following modifications described in detail above: a) 70-30, customer-shareholder sharing is included; b) wheeling revenues are included; c) REC revenues are excluded; d) natural gas and electricity swaps are excluded; e) Utah allocated costs and retail sales megawatt hours are used in the calculation; f) other implementation conditions, requirements and procedures specified herein.
2. PacifiCorp shall file a revised Schedule 94, consistent with the terms of this Report and Order, within 30 days of its issuance.
3. PacifiCorp shall implement the ratemaking mechanism approved herein according to the schedule, design specifications and requirements set forth in this Report and Order.
4. The EBA working group shall be established and perform the analyses and reports specified herein.

DATED at Salt Lake City, Utah, this 3rd day of March, 2011.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#71339