- 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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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.

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[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:

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

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,

[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