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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

POST-HEARING BRIEF OF

ROCKY MOUNTAIN POWER

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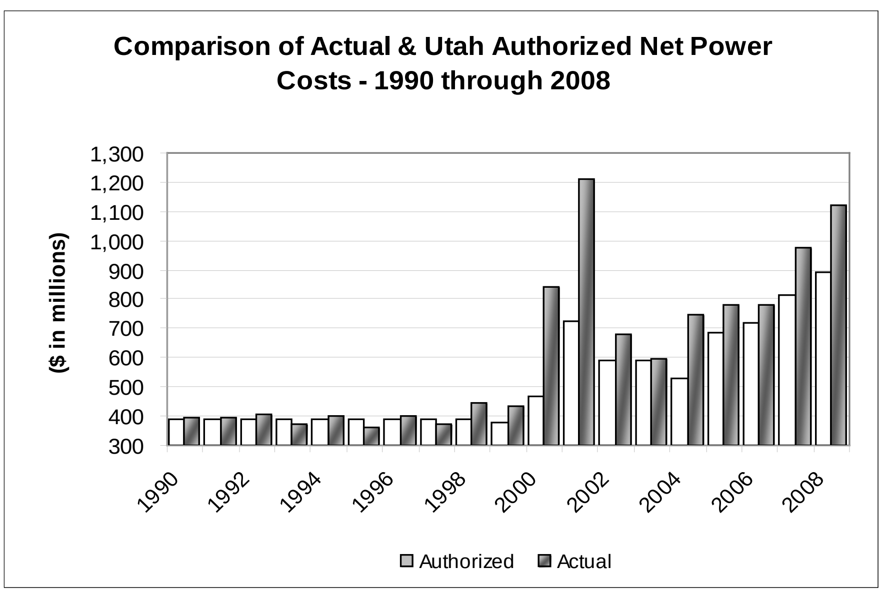
Rocky Mountain Power ("Rocky Mountain Power" or the "Company") submits this post-hearing brief to demonstrate that the Energy Cost Adjustment Mechanism ("ECAM") proposed by the Company is needed to assure that Rocky Mountain Power's rates are just and reasonable for the benefit of both the Company and its customers and is, therefore, in the public interest. The Company's ECAM is simple, balanced and fair and is consistent with similar mechanisms adopted in a substantial majority of states. Thus, the ECAM should be approved by the Commission on a pilot basis effective February 18, 2010.

I. INTRODUCTION

Rocky Mountain Power has not come close to earning its authorized return on equity ("ROE") for over a decades. A major reason for this is that the Company's actual net power costs ("NPC") have been substantially in excess of the amount included in rates during general rate cases. This trend started in 1998 and became more pronounced in 2000 as shown in the following table:[1]



[1] Duvall Supp. Direct Phase I (8/17/09), l. 83.

Even ignoring the effects of the western energy crisis in 2000 and 2001, the Company's in-rates NPC has been less than actual NPC by a wide margin in every year except 2003. In fact, the differences in 2007 and 2008 are in excess of $160 million and $230 million on a total Company basis, respectively. The Utah portion of these differences largely accounts for the Company's under earning in those years in Utah.

A public utility is entitled to have its rates set at a level that reflects its prudent costs of providing service to customers and allows it a reasonable opportunity to earn the ROE found just and reasonable by the Commission. Customers are entitled to have rates set at a level that is no more than necessary for the foregoing.

Traditional ratemaking assumes that a utility is afforded the requisite reasonable opportunity to earn its authorized ROE by setting rates for a rate-effective period based on the level of costs reasonably expected to be incurred during the rate-effective period. When the level of costs in the rate-effective period can be determined with reasonable confidence, it would be expected that a utility would earn around its authorized ROE most of the time—with the likelihood that it would under earn approximately equal to the likelihood that it would over earn. Obviously, this has not been the case with the Company for two reasons.

First, Rocky Mountain Power's projections of NPC are not the basis on which rates have been set. Rather, the Company's original projection becomes the upper bound. The Company's model and assumptions are criticized by other parties who suggest various deductions from the projected amount, some of which are accepted by the Commission. When new information becomes available suggesting that the Company's original projection was too low, the Company typically is not allowed to introduce it because parties claim they would not have sufficient time for review. In fact, the contest on NPC in litigated general rate cases becomes a battle of competing models and assumptions about future events which it is apparent no one can reliably predict. Ultimately, as illustrated by the above table, the level of NPC adopted in general rate cases has been reduced to the point that it does not represent a reasonable estimate (*i.e.*, an equal probability of being high or low) of NPC in the rate-effective period.

Second, even though Rocky Mountain Power has every incentive to accurately predict and control NPC, it has consistently been unable to do so. This is perhaps the most persuasive evidence that NPC are highly volatile and largely outside the control of the Company. The Company does not contend that it has no ability to predict and control some aspects of NPC. That is not the issue. The issue is that the Company cannot predict or control the cost of fuel and electricity required to meet its obligation to serve customers when loads or generating capacity vary in the short term from those on which NPC projections were based. It is undisputed that short-term loads and generation from renewable resources vary in unpredictable and uncontrollable ways and that the risk of price variations during these short-term periods cannot be hedged. This variability alone accounts for potential variations in NPC that are as great or greater than total NPC.

Under these conditions, the current general rate case process fails to set rates that reflect costs reasonably expected to occur in the rate-effective period and equally fails to provide the Company with a reasonable opportunity to earn its authorized ROE.

When costs are substantial, highly volatile and largely outside the control of the utility, there is a high risk of over-recovery or under recovery using the traditional ratemaking process. To mitigate this risk, regulators around the country have approved ECAM-type mechanisms for the electric utilities in their jurisdictions. The sole exception is Utah.[2]

[2] This is not to suggest that the Commission has been derelict. Rocky Mountain Power's predecessor had an ECAM prior to 1992, but voluntarily requested that it be discontinued because, based

Fully reconciling NPC through the Company's proposed ECAM is the most efficient means of managing the risk of variability for both customers and the Company. In the current environment with NPC being highly volatile and beyond the control of the Company, a reasonable forecast of NPC would be just as likely to over-recover as under-recover actual NPC. This is the risk to customers of not adopting an ECAM. Adopting an ECAM reduces the risk to both the Company and customers of the variability of NPC that neither the Company nor customers can control. Moreover, under the Company's proposal, the Company continues to be subject to full prudence reviews, ensuring customers only pay for reasonable costs.

In cross examination of witnesses at the hearings, the Commission asked several questions regarding whether an ECAM shifts risks to customers that the Company is better able to mitigate or control. These questions raised two separate types of risk. The first type of risk is the risk that components of NPC will be procured imprudently. The Company currently bears 100% of that risk, and it will not shift under the Company's ECAM. While not all adjustment mechanisms in other states have always had both features (thus leading to a potential risk shifting), the Company's proposal has both a prudence review and a full reconciliation to actual prudent costs, ensuring that no prudence risk is shifted. The second type of risk is the risk that customers will pay more or less for service than the prudent costs of serving them. Stated from the Company's perspective, the risk is that the Company will not recover the actual costs it incurs in serving customers even when it is 100% prudent. The ECAM does *not* shift this cost risk—*it eliminates the risk for both customers and the Company*. It accomplishes this through

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on the circumstances then present, it believed that NPC were relatively stable and controllable and that an ECAM would not be needed in the anticipated competitive retail market. The Company's view regarding stability and controllability of NPC apparently proved accurate during the next several years. However, a competitive retail market never developed, and volatility and non-controllability increased substantially as commodity markets developed resulting in the current situation.

the reconciliation mechanism proposed by the Company. Elimination of unnecessary risk should be an objective of regulation, and it is critical for the Commission to recognize that the dead bands and sharing mechanisms proposed by the other parties thwart achievement of that objective.

It is understandable why some parties like the status quo—their rates have been lower for many years than their cost of service. Therefore, desiring to perpetuate that situation, they oppose adoption of an ECAM. As a fall back, they suggest an ECAM that is not fully reconciled because it contains dead bands or sharing mechanisms that ensure the Company will never recover its cost of service so long as rates are set based on unreasonably depressed NPC forecasts. Thus, adoption of an ECAM with dead bands and sharing mechanisms perpetuates the incentive for some parties to advocate for depressed NPC forecasts. Adoption of these proposals will not eliminate the current battle of models and assumptions in general rate cases.

Although dead bands and sharing mechanisms have been adopted in a minority of states, the sharing mechanisms in other states are often focused on the revenue side, not the cost side, and provide the utility with an opportunity to share in revenues in excess of forecast. Examples include revenues from wholesale sales in excess of those projected, thus, allowing the utility to keep a portion of excess revenues rather than refund all of it to customers. Sharing of renewable energy credit ("REC") revenues could be another example. However, the dead bands and sharing mechanisms proposed by the other parties in this case are inconsistent with the Company's right to recover its prudently incurred costs and the customers' right to pay no more than prudently incurred costs.

Moreover, sharing mechanisms like those proposed by the other parties in this case provide no incentive for the Company to procure power prudently or at a lower cost because

(1) the volatility in NPC that can cause it to exceed forecast NPC is largely outside the Company's control; (2) the Company cannot refuse to purchase power or fuel when customers require service and await better or lower prices—it can only act prudently when it does purchase; and (3) prudence or lack thereof has no impact on the percentages of sharing or the amount of the dead band.

Indeed, the Commission should be cognizant that dead bands and sharing bands do, in fact, create one incentive—the incentive for some parties to advocate for depressed NPC forecasts to ensure that customers do not pay all the costs to serve them. It is for this precise reason that the Company would rather have a fully reconciled ECAM based on historic costs (with a forecast test year for other costs) than an ECAM based on forecast NPC but with sharing bands and dead bands. Under the former, the Company can experience cash-flow problems but at least it ultimately recovers its costs; under the latter, it may never recover its costs at all, which is the ultimate, and ultimately terminal, cash-flow problem.

It is absurd, and frankly somewhat offensive, to suggest that traders and their managers will act differently if the Company only recovers 70% of prudent incremental NPC than if it recovers 100%. Rocky Mountain Power does not have the latitude to refuse to incur NPC when it does not like the commodity market price for fuel or electricity. It must fulfill its obligation to serve customers. It does so at the best prices currently available. Thus, rather than providing an effective incentive, dead bands and sharing mechanisms as proposed in this case simply assure that customers will pay a different amount than the prudent cost to serve them.

For years, regulation of public utilities has been grounded in prudence reviews of utility conduct.[3] Knowing that actions will be subject to after-the-fact prudence review is a powerful and effective incentive for utilities to engage in appropriate behavior. Prudence review is the standard incentive used in ECAMs around the country, and it is not reasonable to suggest that this incentive is inadequate or does not work. Indeed, the other parties appear to agree because none of them was willing to eliminate the prudence review. Although claiming that prudence reviews were extremely difficult, if not impossible, the parties still intend to do them even if dead bands or sharing mechanisms are adopted.

The performance standards, load growth adjustments and retroactive rate adjustments based on interjurisdictional allocation issues recommended by other parties are unnecessary, bad policy or illegal. On the other hand, the Company's proposal to provide customers with the benefit of actual REC revenues in the ECAM is fair and sensible given the relationship between REC revenues and NPC and their similar characteristics. Including REC revenues in the ECAM proposed by the Company will assure that customers receive their full benefit and consistent treatment with NPC.

Parties offered different opinions on the impact of an ECAM on management incentives throughout the course of this docket. However, there was no debate that the Company currently has every incentive to accurately forecast and manage NPC. Yet, despite these incentives, Rocky Mountain Power's rates have consistently and substantially under-recovered NPC for many years. The Company is not proposing to recover imprudent costs or to earn a profit on NPC. It simply wants rates that compensate it for the prudent costs of serving—no more and no

[3] During the 1980s and early 1990s, the Commission used prudence reviews as the sole incentive with the Company's Energy Balancing Account ("EBA"). The EBA was a dollar-for-dollar recovery mechanism even though, at the time, the Company had more control of its NPC than it does now.

less. That is what the law requires for both the Company and its customers and what the Company seeks through its proposed ECAM.   The Commission should approve the simple and straightforward ECAM proposed by the Company on a pilot basis. If refinements prove necessary during the course of the pilot program, they can be implemented as the ECAM goes forward.

II. PROCEDURAL HISTORY

Rocky Mountain Power filed its application for an ECAM on March 16, 2009, over three months in advance of its general rate case application in Docket No. 09-035-23 ("General Rate Case"). This was done in compliance with Commitment U 23 in Docket No. 05-035-54 and the statute authorizing energy balancing accounts, Utah Code Ann. § 54-7-13.5, so that the ECAM could be implemented on a base level of NPC found just and reasonable in the General Rate Case. On May 5, 2009, the Commission held a technical conference at which David Boonin of National Regulatory Research Institute discussed the pros and cons of ECAM-type mechanisms, confirmed that all non-restructured jurisdictions except Utah have approved ECAM-type mechanisms for NPC and provided an example of an ECAM that was essentially identical to the ECAM proposed by the Company.

In response to claims that the Company's filing was insufficient and following argument on the scope of issues and scheduling, the Commission issued a procedural order on June 16, 2009, denying motions to dismiss and dividing the case into two phases. Following further argument about scheduling in this docket in relation to the General Rate Case and whether an ECAM could be implemented at the conclusion of the General Rate Case, the Commission issued a Scheduling Order in which it adopted a schedule that "can accommodate parties' interests in both dockets."[4] The Company understood this to mean that it would be allowed to implement the ECAM concurrent with, or shortly after, the effective date of rates set in the General Rate Case even though the hearing in Phase I was not scheduled until January 2010.

Phase I proceeded with the filing of additional testimony on need for an ECAM and the public interest, and a hearing was held on January 12, 2010. The Commission issued its Report and Order on Phase I on February 8, 2010. Despite opposition to proceeding further from the Office of Consumer Services ("OCS"), Utah Association of Energy Users ("UAE"), Western Resource Advocates ("WRA"), Wal-Mart Stores, Inc. and Sam's West, Inc. ("Wal-Mart") and Salt Lake Community Action Program ("SLCAP"), the Commission agreed with the Company and the Division of Public Utilities ("DPU") that the case should proceed to Phase II to consider the ECAM design proposed by the Company and any alternatives proposed by others.[5]

On February 9, 2010, the Company filed a motion for a deferred accounting order for incremental NPC incurred following the Commission's revenue requirement order in the General Rate Case on February 18, 2009. The purpose of the filing was to allow implementation of the ECAM concurrently with the date rates set in the General Rate Case would be effective. Other parties initially opposed the motion, but ultimately stipulated to the Commission granting it along with an application for a deferred accounting order for incremental REC revenues filed by UAE in Docket No. 10-035-14 on February 22, 2010. The stipulation provided that parties could address whether deferred REC revenues should be included in the ECAM in this case and

[4] Scheduling Order, Docket No. 09-035-15 (Utah PSC Aug. 4, 2009) at 1.

[5] Report and Order, Docket No. 09-035-15 (Utah PSC Feb. 8, 2010) at 1-2. The Commission also directed the parties to address whether "the [C]ompany's use of natural gas hedging and the level of and reliance on market energy [are] affected by the use of ECAM" in response to issues raised by the OCS. *Id.* at 2.

provided for division of Phase II, into two parts to address hedging and market reliance and ECAM design.[6]

Technical conferences were held on the Company's hedging program on May 18 and June 3, 2009 in Docket No. 09-035-21 and on February 24, 2010 in this docket. During those conferences, the Company presented information on the policies and standards governing its hedging program and demonstrated how the hedging program had substantially reduced the risk of upward volatility in NPC for the benefit of customers. The information also demonstrated incidentally that the hedging program during the period January 2004 through March 2009 had resulted in a cumulative savings to customers of approximately $100 million (excluding the benefits of the long-term Hermiston natural gas contract that further increased the benefit to customers).[7] The parties filed further testimony on hedging and market reliance, and, following a hearing on August 17, 2010, the Commission concluded that it would not issue an order on Phase II-1 at that time.[8]

The parties filed testimony on ECAM design issues, and hearings were held in Phase II-2 on November 1 and 2, 2010.

As noted by the Commission during the hearings in this case, the testimony in all three portions of the case overlapped substantially. For example, extensive testimony on incentives and hedging was presented in all portions of the case. In addition, parties such as the OCS, UAE and WRA asserted in all three portions of the case that an ECAM was not in the public interest

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[6] Stipulation and Joint Motion for Deferred Accounting Orders in Docket Nos. 09-035-15 and 10-035-14 and Scheduling in Docket Nos. 09-035-15, Docket No. 09-035-15 & 10-035-14 (Utah PSC May 4, 2010) at ¶¶ 13, 17.

[7] Duvall Rebuttal Phase II-1 (7/20/10), p. 5, n. 1.

[8] Transcript of Hearing ("Tr.") 8/17/10 at p. 264, ll. 8-9.

and should not be approved.[9] On the other hand, certain positions of the parties evolved during the case. For example, in Phase I, the DPU stated that it would likely recommend that the ECAM not include all elements of NPC,[10] but, by Phase II-2, the DPU affirmatively argued that it would create perverse incentives to exclude any element of NPC from the ECAM.[11] In Phase II-1, the OCA argued that if an ECAM were adopted, it should not include costs associated with natural gas hedging or natural gas purchases and, possibly, some level of front office transactions ("FOTs").[12] By Phase II-2, the OCA strenuously protested that other parties' claims that its position was to exclude these elements from the ECAM were inaccurate.[13]

This brief will not extensively review the evidence in Phase I and Phase II-1. However, given the overlapping nature of the evidence presented in all three portions of the case and the continuing position of some parties that an ECAM is not needed or in the public interest, Rocky Mountain Power will briefly review the overwhelming evidence that NPC are substantial, highly volatile and largely outside the control of the Company and that ECAM-type mechanisms are the universally accepted standard for dealing with NPC to assure that rates are just and reasonable. It will also briefly review the undisputed evidence that the Company's market reliance has substantially benefitted customers and that its hedging program not only achieves its objective of reducing upward volatility in NPC to the benefit of customers, but has also incidentally resulted in substantially lower NPC during the period examined by the parties.

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[9] *See e.g.*, Beck Direct Phase I (11/16/09), ll. 23-24; Higgins Direct Phase I (11/16/09), ll. 49-50; Kelly Direct Phase I (11/16/09), p. 2, ll. 19-20; Gimble Surrebuttal Phase II-1 (8/10/10), ll. 33-34; Kelly Surrebuttal Phase II-1 (8/10/10), ll. 430-432; Gimble Direct Phase II-2 (8/4/10), ll. 24-28; Higgins Direct Phase II-2 (8/4/10), ll. 54-56; Kelly Direct Phase II-2 (8/4/10), ll. 248-250.

[10] Peterson Direct Phase I (11/16/09), ll. 425-427.

[11] Peterson Direct Phase II-2 (8/4/10), ll. 509-510.

[12] Gimble Direct Phase II-1 (6/16/10), ll. 739-741, 753-754.

[13] Gimble Surrebuttal Phase II-2 (10/13/10), ll. 182-238.

III. ARGUMENT

A. The ECAM Is Needed to Assure that the Company's Rates Are Just and Reasonable.

"A just and reasonable rate is one that is sufficient to permit the utility to recover its cost of service and a reasonable return on the value of property devoted to public use." *Utah Dep't of Business Regulation v. Public Service Comm'n*, 614 P.2d 1242, 1248 (Utah 1980) ("*Wage Case*").[14] "To avoid confiscatory rates on the one hand and exploitive rates on the other, the Commission must determine what a just and reasonable rate is . . . based on a utility's cost of service. A cost-of-service standard mandates that rates produce enough revenue to pay a utility's operating expenses plus a reasonable return on capital invested." *Stewart v. Utah Public Service Comm'n*, 885 P.2d 759, 767 (Utah 1994). Thus, rates that are not reasonably expected to cover a utility's prudent costs of providing service to customers, no more and no less, are not just and reasonable.[15]

There are well-recognized exceptions to this standard method of rate making. For example, it has long been recognized that recovery of NPC based on projections in general rate cases is problematic. In *Utah Dep't of Business Regulation v. Public Service Comm'n*, 720 P.2d 420 (Utah 1986) ("*EBA Case*"), the court acknowledged that fuel costs comprise a substantial

[14] *See also American Salt Co. v. W.S. Hatch Co.*, 748 P.2d 1060, 1063 (Utah 1987) ("A just and reasonable rate is one that is sufficient to permit a utility to recover its costs of service and earn a reasonable return for its enterprise.").

[15] *See also West Ohio Gas Co. v. Public Utilities Comm'n*, 294 U.S. 63, 72-73 (1935) (recovery of expenses must be allowed where there is no showing of inefficiency or improvidence); *Tenoco Oil Co. v. Dep't of Consumer Affairs*, 876 F.2d 1013, 1020 (1st Cir. 1989) ("To be just and reasonable, rates *must* provide not only for a company's costs, but also for a fair return on investment. Rates which fall below this standard are 'confiscatory.'") (emphasis added); *International Telecharge, Inc. v. Wilson*, 573 So.2d 816, 818 (Fla. 1991) ("The PSC is responsible for reviewing utility investment and operating expenses to ensure that rates are fair, just, and reasonable; and it *must* allow the public utility an opportunity to earn a fair return on its investment.") (emphasis added); *Baltimore Gas & Elec. v. Public Service Comm'n*, 201 A. 2d 1307, 1309 (Md. Appl. 1986) (explaining that "just and reasonable rates" "*must* enable the company to recover its 'necessary and proper expenses' and to provide a 'reasonable return' to the company's investors") (emphasis added).

portion of the Company's expenses and that, although they had earlier been relatively stable and predictable, they began to escalate in rapid and unanticipated ways in the early 1970s. The court noted that this justified legislation in Utah in 1975 allowing these costs to be treated differently than other utility expenses and to be trued-up between general rate cases. *Id.* at 421.

Dr. McDermott explained why regulators have generally concluded that NPC could not be reasonably dealt with through the normal ratemaking process and needed to be subject to true-up mechanisms to assure that utilities recovered their actual prudent costs for NPC, no more and no less.[16] When these mechanisms were first adopted in the 1970s, the problem was rapidly escalating fuel costs. In more recent years, the problem is tremendous volatility, both up and down, in energy costs and wholesale revenues as natural gas and electricity have become commodities.

It is undisputed that an ECAM is justified if NPC are substantial, highly volatile and largely outside the control of the Company.[17] The Company presented compelling evidence that these conditions are satisfied.[18] Based on the data, tables and exhibits in Mr. Duvall's, Mr. Graves' and Dr. McDermott's testimony in Phase I, there can be no question that NPC are substantial and highly volatile.[19] Nonetheless, certain witnesses claimed that the Company had

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[16] McDermott Supp. Direct Phase I (8/17/09), ll. 209-346.

[17] *See, e.g.*, Boonin, David, "Energy Cost Adjustment Mechanisms" (5/9/2009), p. 3; Duvall Direct Phase I (3/16/09), ll. 37-39; Graves Supp. Direct Phase I (8/17/09), ll. 54-61; McDermott Supp. Direct Phase I (8/17/09), ll. 27-42, 378-402; Peterson Surrebuttal Phase I (1/5/10), ll. 54-55; Chernick Surrebuttal Phase I (1/5/10), ll. 12-14 (applying test); Higgins Direct Phase I (11/16/09), ll. 56-60; Kelly Direct Phase I (11/16/09), p. 8, ll. 12-18 (applying test).

[18] *See, e.g.*, Duvall Direct Phase I (3/16/09), ll. 37-70; Duvall Supp. Direct Phase I (8/17/09), ll. 70-207; Duvall Rebuttal Phase I (12/10/09), ll. 131-135, 187-224, 239-329, 364-385; Graves Supp. Direct Phase I (8/17/09), ll. 64-95, 179-204, 227-366, 647-854; Graves Rebuttal Phase I (12/10/09), ll. 61-425; McDermott Supp. Direct Phase I (8/17/09), ll. 425-657; McDermott Rebuttal Phase I (12/10/09), ll. 142-284.

[19] *See, e.g.*, Duvall Direct Phase I (3/16/09), RMP Ex. GND-1; Duvall Supp. Direct Phase I (8/17/09), Tbls. 1-3; Duvall Rebuttal Phase I (12/10/09), RMP Ex. GND-1R, GND-2R; Graves Supp.

not demonstrated that NPC were sufficiently volatile to justify an ECAM.[20] The Company fully rebutted these claims showing that volatility of NPC is increasing and that NPC were four times more volatile than other costs.[21] Other parties' witnesses also quibbled about whether NPC were largely outside the control of the Company. Generally, the witnesses made this claim on the basis that the Company owns some coal resources and has a hedging program.[22] However, the Company rebutted this claim by demonstrating that its percentage of owned coal was declining and that, in any event, the large swings in NPC from forecast to actual were attributable to balancing transactions required because of short-term changes in load and resources that could not be predicted or hedged.[23] If there were any doubt about the Company's position, it is fully resolved by reference to the table at the start of this brief. It is undisputed that Rocky Mountain Power has had every incentive to accurately project its NPC in general rate cases and to

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Direct Phase I (8/17/09), Figs. 1-6; Graves Rebuttal Phase I (12/10/09), Figs. 1-10; McDermott Supp. Direct Phase I (8/17/09), Figs. 2-5, Tbls. 1-3; McDermott Rebuttal Phase I (12/10/09), Figs. 1-2.

[20] *See, e.g.*, Chernick Surrebutttal Phase I (1/5/10), ll. 536-538; Higgins Direct Phase I (11/16/09), ll. 61-63.

[21] *See, e.g.*, Graves Rebuttal Phase I (12/10/09), ll. 281-425 (*see* particularly Figs. 6-10); McDermott Rebuttal Phase I (12/10/09), ll. 141-195 (*see* particularly Fig. 1 comparing the volatility of NPC with non-NPC expenses from 1992 through 2008).

[22] *See, e.g.*, Chernick Direct Phase I (11/16/09), ll. 233-235; Higgins Surrebuttal Phase I (1/5/10), ll. 195-197.

[23] *See, e.g.*, Duvall Supp. Direct Phase I (8/17/09), ll. 189-207 (showing that the Company has reduced its reliance on coal plants from 66% of its resource mix in 1992 to 43% in 2009 and that coal supplied from captive coal mines has decreased from 60% to 30% during the same period); Graves Rebuttal Phase I (12/10/09), ll. 17-25 ("RMP's hedging practices do not and cannot eliminate enough volatility in NPC to make an ECAM unnecessary. In particular, two components of NPC—net short-term sales revenue and natural gas expenses—exhibit so much variability that an ECAM-like mechanism will be needed to protect RMP and its customers, even with RMP's substantial hedging practices. These two components of NPC are also extremely difficult to forecast, with the result being that past rate case projections of total NPC have had annualized variances between actual and allowed costs of up to $300 million or more, on a total system basis.") *See also*, *id.*, ll. 61-277 (showing that net short-term sales vary between negative $218 million in 2001 to as much as positive $669 million in 2009 and have varied from projections by from -112% to 60% and that actual natural gas expenses have varied from $185 million in excess of projected to $42 million less than projected during the same period).

thereafter keep its NPC as low as possible.[24] Nonetheless, since 1998, NPC allowed in rates has been substantially less than actual NPC incurred by the Company.[25] It is beyond reasonable debate that NPC in total are highly volatile and largely outside the control of management.

Every state that is not restructured through direct access except Utah has ECAM-type mechanisms in place for their electric utilities to deal with the problem of substantial, highly volatile and largely uncontrollable NPC.[26] The evidence presented in this case overwhelmingly demonstrates that an ECAM is also needed in Utah to assure that the Company's rates are just and reasonable.

B. The Company's Proposed ECAM Provides Proper Incentives for Prudent Conduct.

1. Prudence Reviews Work, Provide Proper Incentives and Are Contemplated by Section 54-7-13.5.

The Company's evidence demonstrated convincingly that prudence reviews included as part of the ECAM process are the best and most effective incentive to assure that the Company continues to meet its obligation to provide reliable service to customers at the lowest reasonable cost. Dr. McDermott presented uncontroverted evidence that prudence reviews are used as the sole incentive in most states and that regulators have been fully capable of using them to disallow imprudent costs.[27] Messrs. Bird and Duvall explained why prudence reviews are the only effective incentive to good utility conduct with respect to NPC.[28] Rather than focusing on competing models in general rate cases, the ECAM with prudence reviews allows the Commission and the parties to focus their attention on actual results. Combined with ECAM

[24] *See, e.g.*, Tr. 11/2/10 at 316-317.

[25] Duvall Supp. Direct Phase I (8/17/09), ll. 83, 94-95.

[26] McDermott Supp. Direct Phase I (8/17/09), ll. 687-690.

[27] Tr. 11/1/10 at 267, 270-271.

[28] Duvall Rebuttal Phase II-2 (9/15/10), ll. 103-132; Bird Rebuttal Phase II-2 (9/15/10), ll. 228-229; Tr. 11/1/10 at 68, 218, 220-222, 238-239.

reconciliation and the IRP process, prudence reviews are a valuable incentive for the utility to attempt to achieve the lowest NPC reasonably available.[29]

Other parties claimed that prudence reviews were simply too complex and too difficult in the context of an electric utility's NPC to be effective.[30] In fact, the DPU worried that it did not have sufficient staff or resources to effectively audit the Company's ECAM filings.[31] However, the DPU admitted that it had not contacted any other state commission staffs to determine how they are able to perform these audits.[32] In addition, it is undisputed that the staffs in Idaho and Wyoming, neighboring states in which the Company already has ECAMs in place, conduct ECAM prudence reviews.[33] Certainly, since every non-restructured state except Utah has an ECAM and very few have sharing mechanisms or performance standards, it is obvious that the great majority of states rely on prudence audits to assure that ECAMs do not result in lax management of NPC and unjust and unreasonable rates.

Even more telling, the OCS and UIEC relied on the fact that the Company's actions with respect to certain aspects of NPC could be reviewed after the fact. Mr. Gimble testified that a separate filing and consideration of all facts and evidence should occur if NPC varied

[29] *Id. See also* Duvall Rebuttal Phase II-2 (9/15/10), ll. 107-108; Tr. 11/1/10 at 235-236, 238-239, 253.

[30] *See, e.g.* Brubaker Direct Phase II-2 (8/4/10), p. 5, ll. 10-17; Kelly Surrebuttal Phase II-2 (10/13/10), ll. 98-109; Tr. 11/2/10 at 350, 545. One of these witnesses acknowledged that the prudence of Questar Gas's gas balancing account is regularly and successfully audited, but claimed that this is possible because it is so much more simple. *See, e.g.* Brubaker Directr Phase II-2 (8/8/10), p. 5, ll. 17-18. Rocky Mountain Power knows that the DPU was able to audit its EBA prior to 1992 and that regulators all over the country are capable of successfully auditing ECAMs currently. McDermott Rebuttal Phase I (12/10/09), ll. 593-620; Tr. 11/1/10 at 16, 48.

[31] Peterson Direct Phase II-2 (8/4/10), ll. 192-194; Tr. 11/2/10 at 350.

[32] Tr. 11/2/10 at 351-352.

[33] *Id.* at 351, 515.

substantially rather than allowing an automatic recovery as proposed by the DPU.[34] Mr. Brubaker defended his proposed performance standards by testifying that "[w]ith or without my proposal, an auditor certainly would be expected to examine the operation of all of the Company's mines and coal-fired plants" and "the correct actions . . . would be relatively easy to defend."[35] Thus, these witnesses recommended prudence audits as the appropriate approach to dealing with certain issues that might arise. The fact is that the DPU, OCS and other parties currently regularly review the prudence of the Company's NPC in general rate cases and raise questions when they believe something is inappropriate. It is not necessary to review every transaction to determine whether conduct is prudent. Statistically determined samples can be used and comparisons can be made with past history, averages and projections to determine if there is reason to look deeper.[36]

It is somewhat ironic for the DPU to suggest that the Company must accept as a given tens and perhaps hundreds of millions of dollars in under earning because the DPU does not have a sufficient staff to appropriately audit a mechanism generally accepted as the appropriate tool to regulate NPC and to assure that the portion of rates attributable to NPC are neither too high or too low.

In any event, no party was willing to give up the right to audit NPC if a dead band or sharing mechanism were adopted.[37] Thus, the parties will still audit NPC, difficult as they claim that might be, and will undoubtedly recommend disallowances in instances where they believe the Company has acted imprudently. The Company fully expects that if its NPC deviate

[34] Gimble Rebuttal Phase II-2 (9/15/10), ll. 503-507.

[35] Brubaker Surrebuttal Phase II-2 (10/13/10), p. 5, ll. 20-23, p. 9, ll. 18-19.

[36] Duvall Rebuttal Phase II-2 (9/15/10), ll. 464-467; Tr. 11/1/10 at 280-282.

[37] Duvall Rebuttal Phase II-2 (9/15/10), ll. 108-109.

unreasonably without clear market basis it will be subject to scrutiny and potential disallowance. That, plus a tradition of trying to perform at the highest levels, is what motivates the Company.[38]

Section 54-7-13.5, the statute authorizing approval of an ECAM, mentions that the Commission must find that the ECAM is for "*prudently-incurred costs*" and that "[r]evenues collected in excess of *prudently incurred actual costs*" shall be refunded and "*[p]rudently incurred actual costs* in excess of revenues collected" shall be recovered in a bill surcharge. Utah Code Ann. § 54-7-13.5(2)(b)(ii), (g) and (h) (emphasis added). Thus, findings of prudence are required by the Commission in operation of the ECAM. There is no way for the Commission to make findings of prudence without conducting a prudence review or audit. Thus, prudence reviews are anticipated by the legislature under an ECAM.

2. Dead Bands and Sharing Mechanisms Do Not Provide Proper Incentives, Are Out of the Mainstream and Are Inconsistent with the Statute.

The DPU recommended a dead band of plus or minus 2% in which there would be no recovery or refund of incremental NPC and a sharing mechanism under which customers would bear 70% of incremental NPC and the Company would bear 30% in excess of the dead band. The DPU also recommended that there be no sharing if incremental NPC were 30% or more of forecast NPC in rates.[39] The OCS, UAE and WRA/UCE did not recommend a dead band, but did recommend a sharing ratio of 70-30 with no outside limit.[40]

[38] Bird Rebuttal Phase II-2 (9/15/10), ll. 230-233; Tr. 11/1/10 at 221-222.

[39] Peterson Direct Phase II-2 (8/4/10), ll. 259-260, 344-348, 378-381.

[40] Gimble Direct Phase II-2 (8/4/10), ll. 124-127; Higgins Direct Phase II-2 (8/4/10), ll. 89-91; Kelly Direct Phase II-2 (8/4/10), ll. 206-207. UIEC did not take a position on a sharing mechanism. Tr. 11/2/10 at 450.

a. Dead Bands and Sharing Mechanisms Do Not Provide an Effective Incentive, But Simply Assure that the Company Will Not Recover Prudent Costs.

The rationale for dead bands and sharing mechanisms proposed by other parties was that they are necessary to incent the Company to attempt to achieve the lowest NPC reasonably available.[41] As stated by Messrs. Peterson and Gimble, these parties believe dead bands and sharing mechanisms will require the Company to have "skin in the game."[42] However, beyond the fact that the Company is exposed to differences between actual and forecasted NPC, these parties offered no analysis of why dead bands or sharing mechanisms would change the Company's behavior in any way. They also provided no analytical basis justifying a sharing ratio as great as 70-30,[43] when most states either have no sharing ratios or have much smaller sharing ratios, as discussed below. The Company currently bears 100% of the risk of actual NPC being higher than forecast NPC, yet this even greater incentive has not operated to enable the Company to achieve actual NPC anywhere near the NPC forecasted in setting rates. The issue is not incentives, the issue is that NPC are substantial, highly volatile and largely outside the control of the Company.

On the other hand, the Company's evidence persuasively demonstrated that dead bands and sharing mechanisms would provide no incentive at all to change behavior. NPC and particularly the portion of NPC that deviates substantially from NPC forecasted in a general rate case is the result of transactions by traders buying and selling gas and electricity to balance the Company's short-term load. It makes no sense to suggest that these traders will be more likely to

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[41] Peterson Direct Phase II-2 (8/4/12), ll. 262-263, ; Higgins Direct Phase II-2 (8/4/12), ll. 85-91; Kelly Direct Phase II-2 (8/4/12), l. 212.

[42] Peterson Direct Phase II-2 (8/4/10), l. 460; Gimble Direct Phase II-2 (8/4/10), ll. 131-132.

[43] *See, e.g.*, McDermott Rebuttal Phase II-2 (9/15/10), ll. 265-268; Tr. 11/2/10 at 467-468 (Mr. Gimble admitting that a 70-30 sharing mechanism is a "judgment call").

attempt to achieve better prices with a dead band or 70-30 sharing ratio than they would with no dead band or sharing ratio. They simply attempt to purchase or sell natural gas or electricity at the best prices available in the market at the time and for the location that these commodities are needed.[44] The Company cannot choose whether to buy or sell depending on the market prices. It is obligated to acquire the resources necessary to meet the load required by customers.[45]

Likewise, while exclusion of certain types of NPC from the ECAM could create an incentive for the Company to favor acquisition or use of certain types of resources, the Company's goal is always to plan its resource mix and power acquisition strategy based on the mix of resources that it believes will achieve the lowest cost for customers at reasonable risk over the long term.[46] The purpose of the IRP process is to assure that the Company's plans are articulated, subjected to scrutiny and input, and ultimately, if acknowledged, provide a standard against which future conduct may be evaluated. None of this will change with an ECAM. As Messrs. Duvall and Bird both testified, an ECAM does not change the Company's incentives in any way. It is simply a vehicle for assuring that prudent NPC, no more and no less, is recovered in rates.[47]

Rather than providing a greater incentive for the Company to continue to perform its duty to provide safe, reliable and adequate service at the lowest reasonable cost to customers, dead bands and sharing mechanisms will simply assure that the Company does not recover its prudent

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[44] Duvall Rebuttal Phase II-2 (9/15/10), ll. 121-127; Tr. 11/1/10 at 16, 22-23; Tr. 11/1/10 at 221 (Mr. Bird explaining what motivates traders). *See also* Graves Rebuttal Phase I (12/10/09), ll. 486-494 (explaining why an ECAM would not cause a utility to become lax in its management of NPC); McDermott Rebuttal Phase I (12/10/09), ll. 300-357 and McDermott Rebuttal Phase II-2 (9/15/10), ll. 295-360 (discussing academic studies on the impact of an ECAM on incentives).

[45] Tr. 11/1/10 at 252.

[46] Tr. 11/1/10 at 222.

[47] *Id.* at 22-23, 251-253.

NPC contrary to fundamental principles of rate making and the regulatory compact.[48] The greater the dead band or sharing mechanism, the greater this deviation from appropriate rate making. The Commission certainly would not penalize the Company by slashing an arbitrary 30% from the recovery of rate components found to be 100% just and reasonable, but that is precisely what other parties in this case are advocating.

It is telling that although the other parties recommended dead bands and sharing mechanisms to supposedly assure that the Company retained the proper incentives, none of them believed that these mechanisms eliminated the need for prudence reviews.[49]

b. Dead Bands and Sharing Mechanisms Are Well Out of the Mainstream.

The evidence submitted in the case was that the vast majority of ECAM-type mechanisms approved by commissions in the United States do not have dead bands or sharing mechanisms. Dr. McDermott provided the most comprehensive evidence of the design of ECAM-type mechanisms in other states. His Exhibit KAM-Phase II-2-1R, which no witness challenged, provided an evolution of ECAMs from 1980 to 2010. It showed that most states have never had dead bands and sharing mechanisms, but that of those states that have had them, the trend has been a narrowing or elimination of the dead bands and sharing mechanisms. In fact, Dr. McDermott testified that no state had increased its dead bands or sharing mechanisms.[50] His evidence further showed that sharing, when applied, is usually not applied to fuel and purchased power costs.[51] Of the 47 different operating companies shown on Exhibit KAM-

[48] *Id.* at 17, 42-43, 219.

[49] Duvall Rebuttal Phase II-2 (9/15/10), ll. 108-109.

[50] McDermott Rebuttal Phase II-2 (9/15/10), ll. 136-146 and Exhibit KAM-Phase II-2-1R.

[51] *Id.* at ll. 153-158. *See also* Exhibit KAM-Phase II-2-2R and Exhibit KAM-Phase II-2-3R (showing that in the few instances where sharing ratios are used they generally provide an upside incentive and do not restrict recovery of any portion of fuel and purchased power costs).

Phase II-2-3R, which were selected because they were the comparable companies used by ROE witnesses for estimating cost of equity in the General Rate Case, only 3 have sharing ratios and only three have dead bands. Thus, over 93% of the companies do not have sharing ratios and over 93% do not have dead bands. Again, no witness challenged this evidence.

The other witnesses who provided evidence on this issue were Messrs. Peterson and Higgins. Their evidence was of smaller groups of companies. Even looking at companies hand picked by witnesses who advocated a dead band and 70-30 sharing ratio, it is apparent that most ECAMs around the country do not have dead bands and that 70-30 sharing ratios are almost non-existent. Most companies in their exhibits have no sharing ratios. Of those that have sharing ratios, most are 90-10 or less.[52]

Rocky Mountain Power does not suggest that the Commission is required to approve an ECAM with no dead band or sharing mechanism because the vast majority of other states do not have dead bands or sharing mechanisms in their ECAM-type mechanisms. However, the fact that states that have been regulating electric utilities for many years utilizing ECAM-type mechanisms do not have them is a strong indication that dead bands and sharing mechanisms are not necessary to assure that utilities operate in a reasonable manner. As Dr. McDermott testified, it is not reasonable to assume that regulators in other states are incompetent or are allowing utilities to charge rates that are not just and reasonable.

c. Dead Bands and Sharing Mechanisms Are Inconsistent with Section 54-7-13.5.

Section 54-7-13.5, the statute specifically authorizing energy balancing accounts such as the ECAM, provides that:

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[52] *See* DPU Exhibit 3.7 (33 companies) and UAE Direct Exhibit 1.1D (KCH 1) (11 companies). Dr. McDermott's rebuttal testimony correcting certain information in these exhibits was not challenged by these witnesses.

> (1) (b) "Energy balancing account" means an electrical corporation account for *some or all components of the electrical corporation's incurred actual power costs, including:* (i)(A) fuel; (B) purchased power; and (C) wheeling expenses; and (ii) the sum of the power costs described in Subsection (1)(b)(i) less wholesale revenues.
>
> . . . .
>
> (2) (g) Revenues collected in excess of prudently incurred actual costs *shall*: (i) be refunded as a bill surcredit to an electrical corporation's customers over a period specified by the commission; and (ii) include a carrying charge.
>
> (h) Prudently incurred actual costs in excess of revenues collected *shall*: (i) be recovered as a bill surcharge over a period to be specified by the commission; and (ii) include a carrying charge.
>
> . . . .
>
> (4) (a) *All* allowed costs and revenues associated with an energy balancing account or gas balancing account *shall* remain in the respective balancing account until charged or refunded to customers.

Utah Code Ann. § 54-7-13.5(1)(b), (2)(g) and (h), and (4)(a) (emphasis added).

In accordance with accepted rules of statutory construction, the Commission must first look to "the statute's plain language to determine its meaning,"[53] "presume that the legislature used each word advisedly[,] . . . give effect to each term according to its ordinary and accepted meaning,[54] and read all provisions together attempting to give meaning to each part of the statute.[55] In addition, the word "including" indicates that the list of terms following is not

[53] *Heber Light & Power Co. v. Utah Public Service Comm'n*, 2010 UT 27, ¶ 19, 231 P.3d 1203.

[54] *C.T. v Johnson*, 1999 UT 35, ¶ 19, 977 P.2d 479.

[55] *See Nixon v. Salt Lake City Corp.*, 898 P.2d 265, 268 (Utah 1995) (an "important rule of statutory construction is that a statute should be construed as a whole, with all of its provisions construed to be harmonious with each other and with the overall legislative objective of the statute"); *State v. Redd*, 954 P.2d 230, 235 (Utah App. 1998) ("any interpretation of statutory language that would nullify other statutory provisions is improper").

exhaustive, but that the list suggests the types of things to be included,[56] and the word "shall" is mandatory rather than discretionary.[57]

Based upon these rules, it is clear that the Commission may include some or all components of NPC in the ECAM. These components include, but are not limited to, the enumerated items: fuel, purchased power, wheeling costs and wholesale revenues, and also include similar and associated items such hedging costs incurred to replicate a forward purchase or wholesale sale of fuel or power.[58] As discussed below, no party has recommended that any component of NPC be excluded from the ECAM because doing so would create perverse incentives. At any rate, once the Commission has decided which components of NPC it is going to allow, the Commission may not disallow recovery, or order a sharing, of the components of actual NPC included in the ECAM under the statute. Rather, *all* of the difference between actual prudent costs for the allowed components and the amount included in rates *shall* remain in the balancing account until charged or refunded to customers. "All" does not mean some portion or percentage of a component—it means all; and "shall" does not mean may—it means shall. Thus, dead bands and sharing mechanisms are inconsistent with Section 54-7-13.5.

Commissioner Campbell suggested that the Commission would not be bound by the restrictions of section 54-7-13.5 if it chose to authorize the ECAM under its general jurisdiction

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[56] *Checkrite Recovery Services v. King*, 2002 UT 76, ¶ 7, 52 P.3d 1265 ("[A] statutory definition of a term as 'including' certain things does not restrict the meaning to those items included." Rather, "the word 'include' is ordinarily used as a word of extension or enlargement.") (internal quotations and citations omitted).

[57] *See Pugh v. Draper City*, 2005 UT 12, ¶ 13, 114 P.3d 546 (use of the word "shall" is "usually presumed mandatory and has been interpreted as such previously in [Utah] and other jurisdictions"); *Diener v. Diener*, 2004 UT App 314, ¶ 12, 98 P.3d 1178 ("Ordinarily, the use of the word 'shall' in a statute creates a mandatory condition eliminating any discretion on the part of the courts.").

[58] As discussed by Mr. Duvall and Mr. Bird, the combination of a forward index price physical purchase of natural gas or electricity and a fixed for floating swap is identical to a forward fixed price physical purchase of natural gas or electricity. Tr. 8/17/10 at 28, 36, 53, 62-63, 65-66; Bird Rebuttal Phase II-2 (9/15/10), Exhibit SAB-Phase II-2-1R; Tr. 11/1/10 at 248-250.

rather than under section 54-7-13.5.[59] While Rocky Mountain Power believes the Commission had authority to authorize an ECAM absent passage of section 54-7-13.5,[60] other parties have argued that the Commission could not approve an ECAM absent specific statutory authorization.[61] To avoid unnecessary controversy, parties who regularly appear in the Company's general rate cases cooperated in supporting the passage of legislation designed to address this and other issues in the 2009 General Session of the Utah Legislature. Section 54-7-13.5 was the result. Rocky Mountain Power's application in this docket was filed shortly following the passage of the statute. Given that the legislature has now specifically authorized approval of the ECAM, the Commission's decision on approval should be guided by the terms of the statute. *Cf. Thorpe v. Washington City*, 2010 UT App 297, ¶ 18 ("when two statutory provisions conflict in their operation, the provision more specific in application governs over the more general provision"). Those terms require the refund or surcharge of *all* incremental actual revenues of the components of power costs allowed in the ECAM by the Commission.

Indeed, the only "legal" argument made by any witness that the Commission may approve an ECAM with dead bands and sharing mechanisms relied on section 54-7-13.5. Mr. Higgins' lay argument was that an ECAM can only be approved if the Commission finds that it is "in the public interest." He cited section 54-7-13.5(2)(b)(i) in support of this argument. Mr. Higgins further argued that the Commission could only find the ECAM in the public interest if it included a sharing mechanism.[62] Not only is Mr. Higgins argument belied by the fact that the

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[59] Tr. 11/2/10 at 537-538.

[60] *See Questar Gas Co. v. Utah Public Service Comm'n,* 2001 UT 93, ¶ 12, 34 P.3d 218: *EBA Case,* 720 P.2d at 424.

[61] *See, e.g.,* Motion to Dismiss of the Utah Industrial Energy Consumers, Docket No. 05-035-102 (Utah PSC May 9, 2006).

[62] Higgins Surrebuttal Phase II-2 (10/13/10), ll. 63-69.

great majority of ECAM-type mechanisms adopted in other states include no sharing mechanism or only sharing at levels much less than 70-30, as discussed above, it is contrary to other provisions of the statute Mr. Higgins relied on. If Mr. Higgins' lay interpretation were correct, the requirements that *all* incremental costs *shall* remain in the account until refunded or surcharged and *shall* be refunded or surcharged would be rendered meaningless.

3. The Performance Standards Proposed by UIEC Are One-sided, Premature, Add Complexity and Create Perverse Incentives.

UIEC recommended that if an ECAM were adopted, the Company's recovery under the ECAM should be conditioned on its compliance with performance standards on its production from coal plants, coal mines and wind resources. Its proposed standards for production from coal plants and coal mines were the average for the past five years. Its proposed standard for production from wind resources was 90% of the production projected by the Company when it gained approval for acquisition of the wind resource. UIEC recommended that if the Company did not meet these standards it would not recover incremental NPC unless it could demonstrate that its failure to meet them was not the result of imprudence and that it acquired appropriate substitute resources on a least cost basis.[63]

Other parties that commented on UIEC's proposed performance standards universally opposed them for a variety of reasons. The Company's evidence in Phase I was that performance standards are used as a tool to address problems that arise under an ECAM-type mechanism. It is not useful to adopt standards in a vacuum because they add complexity and may have unintended consequences.[64] On cross examination in Phase II-2, the Company demonstrated that the standards are one-sided, *i.e.*, if the Company falls below the standards, it is

[63] Brubaker Direct Phase II-2 (8/4/10), p. 6, ll. 7-26.

[64] Graves Rebuttal Phase I (12/10/09), ll. 511-517.

required to justify recovery of prudent NPC, but if it exceeds the standards, it receives no benefit.[65]

The DPU opposed the performance standards because they would increase the burden on both the Company and regulators without any indication that the benefits of the standards would outweigh the costs.[66] The DPU also opposed the standards because they are unreasonable—the Company would be expected to fail to meet the standards half of the time—and because they could punish the Company for prudent actions.[67] With regard to wind resources, the DPU opposed the standard because it ignores year-to-year variance, is arbitrary and is an unfair second attempt at a prudence review of wind resources already found prudent by the Commission.[68] The DPU also believed application of the standards could "result in much second-guessing of the Company's actions and protracted analysis and litigation just within the context of an ECAM."[69]

The OCS opposed UIEC's performance standards because they are premature and could have unintended consequences.[70] Consistent with the Company's testimony in Phase I, Mr. Gimble recommended that performance standards be considered if there is a pattern of decline in plant efficiency, availability and maintenance while the ECAM is in effect.[71]

[65] Tr. 11/2/10 at p. 450, l. 8-p. 452, l. 6.

[66] Peterson Rebuttal Phase II-2 (9/15/10), ll. 68-72.

[67] *Id.* at ll. 74-81.

[68] *Id.* at ll. 104-117.

[69] *Id.* at ll. 131-134.

[70] Gimble Rebuttal Phase II-2 (9/15/10), ll. 291-295.

[71] Gimble Rebuttal Phase II-2 (9/15/10), ll. 303-312.

WRA/UCE opposed UIEC's performance standards because they add a great deal of complexity to the ECAM, they could have unintended consequences and they single out only certain resources for review creating an incentive to overuse those resources.[72]

Performance standards are tools available to address specific issues that arise under an ECAM. It is unnecessary to adopt arbitrary standards such as those proposed by UIEC when there is no conduct demonstrating that they are needed. Doing so adds unnecessary complexity to the ECAM and has the potential to create perverse incentives. For these reasons, the Commission should reject UIEC's proposed performance standards.

C. The ECAM Eliminates the Risk that NPC Variability Will Result in Unjust Rates for Both Customers and the Company.

Chairman Boyer, referring to a concept he learned in law school, questioned whether the ECAM inappropriately shifts risks of variations in NPC from the Company to customers when the Company is better able to mitigate the risk.[73] The legal theory on which Chairman Boyer apparently based his questions is strict liability. *See Schaerrer v. Stewart's Plaza Pharmacy*, 2003 UT 43, ¶ 32, 79 P.3d 922 ("strict liability . . . exists in large part as a deterrent and a method of allocating risk of loss among those best equipped to deal with it"). The theoretical bases for strict liability are to deter a manufacturer from making dangerous products or to provide an incentive to make safer products and to spread the catastrophic loss to individual customers caused by defective products over all customers through including the cost of insurance against loss (either from a third party insurer or self insurance) in increased prices paid by all customers. Dobbs, Dan B., *The Law of Torts* (West Group 2000) at 975-976.

[72] Kelly Rebuttal Phase II-2 (9/15/10), ll. 302-324.

[73] *See, e.g.*, Tr. 1/12/10 at 22.

This theory does not apply in the context of utility ratemaking for NPC but, even if it did, it supports an ECAM. With regard to the first basis for the theory, it is analogous in this case to procuring and managing NPC in a prudent manner; i.e., procurement risk. Rocky Mountain Power acknowledges that it has full responsibility for procuring and managing NPC and that customers have none. The Company bears that entire risk that its decisions in managing NPC will be prudent. The ECAM as designed by the Company does not change or shift that risk because it provides for an annual prudence review and a reconciliation to ensure that only prudent costs are recovered. When viewing the literature regarding adjustment mechanisms, the Company respectfully requests the Commission recognize that not all ECAMs provide for prudence reviews and reconciliations like the Company's proposal.

With regard to the second basis for the theory, it is analogous in this case to the risk of customers paying too much or the Company recovering too little; *i.e.*, cost risk. As discussed by the Company's witnesses, if the NPC forecast is a fair and statistically valid one, there should be an equal risk that (1) the Company will not fully recover its prudent NPC and (2) customers will pay more than the Company's prudent NPC.[74] The fact that the Company has substantially under-recovered NPC during the past decade indicates either that a fair and valid NPC forecast has not been used in general rate cases or that current economic conditions tend to result in under forecasts rather than over forecasts. However, there is no reason to assume that these conditions will always be present.[75] But, the Commission need not worry about this risk if it adopts the Company's proposed ECAM. The Company has proposed an annual reconciliation of actual

[74] *See, e.g.*, McDermott Supp. Direct (8/17/09), ll. 361-362; Graves Rebuttal Phase I (12/10/09), ll. 29-36; Tr. 1/2/10 at 55.

[75] Graves Rebuttal Phase I (12/10/09), ll. 63-93; Tr. 11/1/10 at 241-243.

cost with ECAM recovery. This feature eliminates cost risk; it does not shift it.[76] The Company respectfully suggests that elimination of this unnecessary regulatory cost risk is fully consonant with the goals of good regulatory policy and of just and reasonable rates—to cover the prudent cost of service and provide an opportunity to earn a reasonable return, no more and no less.[77]

D. The Company's Proposed ECAM Is Simple, Balanced and Fair.

1. All Elements of NPC Should Be Included in the ECAM.

The evidence supports inclusion of all elements of NPC in the ECAM as proposed by Rocky Mountain Power. Although some parties originally questioned whether all elements of NPC should be included in an ECAM, it was undisputed by the end of the case that exclusion of some elements of NPC from the ECAM would create perverse incentives. As explained by Dr. McDermott in Phase I:

> ECAMs are designed to be comprehensive, i.e., all relevant costs related to fuel and purchased energy are recovered on a level playing field. . . . The reason for this is simple: if some costs were treated one way, and other costs another, perverse incentives could be created. Comprehensive and symmetrical treatment provides an assurance that fuel and purchased energy are treated equally, meaning that a utility would not have an incentive to favor one over the other.[78]

After carefully considering the issue, by Phase II-2 Mr. Peterson agreed:

> [T]he major reason for backing away from specifying relatively narrow accounts for inclusion and exclusion is the effects such a design could have on Company incentives. For example, if short-term power purchases were treated favorably in the ECAM and long-term purchases were excluded, there would be an incentive for the Company to move more to

[76] Tr. 1/12/10 at 53-54; Tr. 11/1/10 at 259-260.

[77] It is important to recognize that the dead bands and sharing bands proposed by the other parties would thwart the elimination of cost risk. In fact, the bands create additional cost risk. The bands are not consistent with good regulatory policy.

[78] McDermott Rebuttal Phase I (12/10/09), ll. 359-441.

> short-term at the expense of long-term purchases. These could occur even if it were not in the best interests of ratepayers to do so.[79]

The same principle applies to exclusion of any element of NPC, including natural gas purchases and hedging. Eliminating these elements would create an incentive for the Company to take actions that might not be in customers' long-term interests. For example, Mr. Peterson testified that excluding hedging would create a perverse incentive for the Company to stop hedging entirely which would result in the full volatility of gas and electricity markets being flowed through to customers.[80]

Commissioner Campbell questioned whether natural gas swaps were beneficial, perhaps suggesting that they should be excluded from the ECAM. As Mr. Bird explained, natural gas swaps are part of a comprehensive hedging program which has successfully reduced the risk of upward volatility in NPC for the benefit of customers. The Company utilizes the most liquid and cost-effective market products, natural gas swaps combined with index-price forward physical purchases, to accomplish the identical price risk management hedging purpose that it would otherwise achieve by relying solely on fixed price forward physical products. If swaps were eliminated and the Company had to rely entirely on fixed price forward physical products, NPC would be higher and credit risk would be increased as a result of fewer trading counterparties, reduced liquidity and higher transaction costs (resulting from higher bid ask spreads).[81] To suggest that natural gas swaps be excluded ignores their purpose—to avoid extreme upward volatility in natural gas prices. If everyone were confident that natural gas prices would only decline in the future, it would make sense for the Company to stop both fixed price forward

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[79] Peterson Direct Phase II-2 (8/4/10), ll. 207-240.

[80] *Id.* at ll. 233-237.

[81] Tr. 11/1/10 at 249-251. *See also* discussion of benefits of hedging in part III.E, below.

physical and financial swap hedges, relying instead solely on the spot market.[82] However, hedging theory recognizes that no one can accurately predict the future and that it is prudent to hedge against the risk that prices will move substantially in an unfavorable direction.

All witnesses who addressed the issue agreed that exclusion of any elements of NPC, even those over which the Company may have more control, would create perverse incentives.[83]

2. REC Revenues Are Related and Similar to NPC and Should Be Included in the ECAM to Assure Consistent Treatment.

At the time Rocky Mountain Power filed its application in this docket, REC revenues were a relatively new and minor aspect of the Company's business and were not part of NPC.[84] However, by the end of 2009 and particularly early in 2010, REC revenues had increased substantially. Following the filing of UAE's application for deferral of incremental REC revenues in Docket No. 10-035-14, the Company concluded that the best way to assure that customers received all of the benefit of incremental REC revenues was to include such revenues in the ECAM. The Company informed other parties of this position in response to UAE's application and in negotiating the stipulation filed in this docket and Docket No. 10-035-14.[85] In fact, the Company insisted that the stipulation provide that parties would have the opportunity to present evidence on inclusion of REC revenues in the ECAM in this docket.[86] At the first

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[82] Several years ago, the Commission rejected a claim that Questar Gas was imprudent because it relied on a balanced portfolio rather than the spot market during a time when spot market prices were favorable. *Re Mountain Fuel Supply Co.*, Docket Nos. 91-057-11 and 91-057-17, 1993 WL 501430 (Utah PSC Sep. 10, 1993).

[83] *See, e.g.*, Graves Rebuttal Phase I (12/10/09), ll. 468-517; Duvall Rebuttal Phase II-1 (7/20/10), ll. 349-351; Bird Rebuttal Phase II-2 (9/15/10), ll. 217-220.

[84] Duvall Supp. Direct Phase II-2 (8/4/10), ll. 54-58.

[85] Duvall Rebuttal Phase II-2 (9/15/10), ll. 276-278.

[86] Stipulation and Joint Motion for Deferred Accounting Orders, ¶ 13.

opportunity to file testimony on the issue, the Company made clear that it was proposing inclusion of REC revenues in the ECAM.[87]

The basis for including REC revenues in the ECAM is that they share many of the characteristics that justify inclusion of NPC in the ECAM. Although much smaller than total NPC, they are relatively large, they have become significantly volatile recently, and the prices for RECs are set in the market and are largely outside the control of the Company.[88] In addition, RECs and energy are generated from the same source. Since the energy generated from the resources that generate RECs are included in the ECAM, REC revenues should also be included in the ECAM.[89]

Most other parties opposed inclusion of REC revenues in the ECAM. The DPU argued that REC revenues should not be included because they are not part of NPC and because they are a recent creation of relatively new government policies. The DPU was concerned that if REC revenues are included, there would potentially be no end to what might be included in the ECAM.[90] Rocky Mountain Power agrees that RECs are a new creation and that they are dependent on governmental policies. However, these arguments also suggest that incremental REC revenues should not be subject to normalized rate recovery at all, let alone through an ECAM. Rocky Mountain Power does not agree that including REC revenues in the ECAM would open the door to inclusion of numerous other items. The Company is not aware of other items similar to REC revenues that might arguably fit in the ECAM. If and when any party proposes inclusion of other items in the ECAM, the parties will be able to present their positions

[87] Duvall Supp. Direct Testimony Phase II-2 (8/4/10), ll. 17-34, 45-51.

[88] *Id.* at ll. 20-29; Duvall Rebuttal Phase II-2 (9/15/10), ll. 276-277.

[89] Duvall Rebuttal Phase II-2 (9/15/10), ll. 270-273; Bird Rebuttal Phase II-2 (9/15/10), l. 251.

[90] Peterson Rebuttal Phase II-2 (9/15/10), ll. 402-408.

on the issue and the Commission will be able to make a decision. Inclusion of REC revenues in the ECAM does not imply that any other cost or revenue not currently part of NPC should be included in the ECAM.

The OCS argued that a basis for difference in treatment between NPC and REC revenues was that REC revenues were a "missed forecast" in the General Rate Case.[91] The Company agrees that REC revenues were a missed forecast in the General Rate Case. However, it is also clear that NPC were a "missed forecast" in the General Rate Case and every other general rate case since 1998.[92] The OCS also argued that REC revenues should be included in the ECAM going-forward, but that the deferred REC revenues should not be included in the ECAM.[93] This position is inconsistent and illogical. As acknowledged by Mr. Gimble, the only basis for the distinction is that the OCS wishes to "maximize[] the benefit to Utah customers" of the deferred incremental REC revenues regardless of whether an ECAM is adopted.[94] The OCS's inconsistent position was also undoubtedly influenced by its recommendation that ECAM balances be shared 70% to customers and 30% to the Company. If the OCS's proposed 70-30 sharing mechanism or any other sharing mechanism is adopted, symmetry and fairness require that the REC revenues be subject to the same sharing mechanism.

UAE argued that the Commission should defer consideration of whether REC revenues should be included in the ECAM,[95] but that the current deferred balance of REC revenues should not be included in the ECAM on the basis that there is no direct or necessary relationship

[91] Gimble Surrebuttal Phase II-2 (10/13/10), ll. 161-162).

[92] Duvall Supp. Direct Phase I (8/17/09), l. 83 (Table 1).

[93] Gimble Rebuttal Phase II-2 (9/15/10), ll. 374-378, 386-387, 401-402.

[94] *Id.* at ll. 392-395.

[95] Higgins Rebuttal Phase II-2 (9/15/10), ll. 82-83, 142-145; Higgins Surrebuttal Phase II-2 (10/13/10), ll. 156-162, 166-169.

between NPC and REC revenues.[96] As discussed above, there clearly is a direct relationship between NPC and REC revenues. UAE also argued that deferred REC revenues should be dealt with in Docket No. 10-035-89, the Company's second application for alternative cost recovery for major plant additions ("MPA II").[97] As with the OCS, the apparent reason UAE opposed inclusion of deferred REC revenues in the ECAM, and the reason it wanted them considered separately in MPA II, was that it was recommending a sharing mechanism for the ECAM that it did not want applied to deferred REC revenues.[98] UAE undoubtedly recognized that it would be more difficult for the Commission to treat deferred REC revenues differently than deferred NPC if it were required to address both of them in the same proceeding.

A stipulation has now been approved in MPA II which moots UAE's argument for dealing with deferral of REC revenues in that docket.[99] In the stipulation, the parties agree that the ratemaking treatment of the deferred REC revenues will not be addressed in that docket.[100] Thus, it makes sense for the Commission to include REC revenues in the ECAM so they are treated the same as NPC and this issue is resolved. Doing so eliminates the need to consider whether rate recovery of deferred REC revenues is justified.

Under the Company's proposed ECAM, customers would realize the benefit of 100% of incremental REC revenues. This is obviously a more fair and balanced treatment than that

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[96] Higgins Direct Phase II-2 (8/4/10), l. 756; Higgins Surrebuttal Phase II-2 (10/13/10), ll. 162-165.

[97] Higgins Rebuttal Phase II-2 (9/15/10), ll. 100-105. Given this recommendation, Commissioner Campbell suggested that parties brief the issue of retroactive ratemaking with respect to incremental REC revenues in MPA II. As noted below, this is no longer necessary. The issue of retroactive ratemaking is briefly addressed in part II.G of this brief in another context.

[98] Duvall Rebuttal Phase II-2 (9/15/10), ll. 263-265; Higgins Rebuttal Phase II-2 (9/15/10), ll. 126-137.

[99] The Commission approved the stipulation from the bench during the hearing in Docket No. 10-035-89 on December 6, 2010, but has yet to issue a written order.

[100] Settlement Stipulation, Docket No. 10-035-89 (Utah PSC Nov. 29, 2010) at ¶¶ 10, 12.

proposed by other parties. There is no good reason to treat REC revenues differently than NPC. Although there has been a significant increase in REC revenues from the amount forecast in the General Rate Case, there have consistently been increases in NPC as great or greater over the course of the past several years.[101] The increase in REC revenues is no more material than the increase in NPC.[102] In addition, it is apparent that it is equally difficult for the Company and the parties to forecast NPC and REC revenues in a general rate case. It would clearly be unfair to allow customers to realize 100% of the benefit of increased revenues but to allow the Company to recover only 70% of increased costs.[103]

3. The Company Has No Objection to Inclusion of Wholesale Wheeling Revenues in the ECAM.

During the hearing on the stipulation for deferred accounting orders in this docket and Docket No. 10-035-14, Commissioner Campbell asked whether including transmission costs in the deferred NPC account without including transmission wheeling revenues created an imbalance. In response to this question, the Company stated that it had no objection to inclusion of transmission wheeling revenues in the ECAM if the Commission believed it appropriate to do so.[104]

4. Approval of the ECAM Will Not Result in Overearning

Mr. Peterson argued in Phase I that approval of the ECAM might result in the Company earning in excess of its authorized ROE.[105] In response, Mr. Duvall demonstrated that

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[101] *See* table at start of brief.

[102] Materiality is typically based on the impact of an expense or revenue on net income and has nothing to do with the percent increase in the item. *In re Westinghouse Securities Litigation*, 90 F.3d 696, 714 n. 14 (3d Cir. 1996) (citing Financial Accounting Standards Board, Accounting Standards: Statement of Financial Accounting Concepts No. 2).

[103] Duvall Rebuttal Phase II-2 (9/15/10), ll. 276-278.

[104] Duvall Supp. Direct Phase II-2 (8/4/10), ll. 80-85.

[105] Peterson Direct Phase I (11/16/09), ll. 247-251. *See also* Tr. 11/2/10 at 421-422.

Mr. Peterson's analysis was incorrect because it relied on financial rather than regulatory reports and ignored varying regulatory treatment of NPC in different Company jurisdictions and, thus, overstated the impact of an ECAM on the Company's earnings.[106] Additionally, Mr. Duvall pointed out that "[s]ince an ECAM recovers only actual net power costs, . . . an ECAM by itself cannot result in earnings above the authorized rate of return."[107] If the Company over earns with an ECAM in place, it is because it has reduced other costs over which it exercises control or because revenues not related to NPC are higher than forecast in setting rates, not because an ECAM is adopted. As noted by Mr. Graves and Dr. McDermott, one of the problems with not having an ECAM is that it motivates the Company to cut costs in areas in which it has control, potentially impairing service to customers.[108]

E. There Is No Need for Further Study of Market Reliance and Hedging Before Adoption of the ECAM

In Phase I, the OCS acknowledged that the Company's hedging program had been effective in reducing volatility in the interest of customers, but nonetheless argued that an ECAM could not be found in the public interest until the Commission conducted a thorough review of the Company's level of market reliance and hedging program.[109] WRA supported this position.[110] The DPU believed the Commission needed further analysis of these issues, but did not agree that this analysis needed to be completed prior to adoption of an ECAM.[111] As a

[106] Duvall Rebuttal Phase I (12/10/09), ll. 458-496.

[107] *Id.* at ll. 497-499.

[108] Tr. 1/12/10 at 54-58.

[109] Beck Direct Phase I (11/16/09), ll. 192-195, 262-265. The OCS also presented a witness on hedging who essentially testified that she had reviewed the Company's hedging program and that the Company complied with the standards governing its program and that doing so reduced the volatility of NPC for the benefit of customers. Schell Direct Phase I (11/16/09), ll. 86-101.

[110] Kelly Direct Phase II-1 (6/16/10); ll. 32-35.

[111] Tr. 11/2/10 at 331-332.

result, the Commission directed the parties to address the effect of an ECAM on market reliance and hedging in Phase II and ultimately established Phase II-1 to address these issues.

In Phase II-1, the DPU made an effort to analyze the effectiveness of the Company's hedging program[112] and suggested that the Company consider splitting its swap strategy into separate electric and natural gas strategies and adding options to the program. The DPU also recommended that the Commission conduct further biennial reviews of the Company's hedging program to establish general guidelines, but did not believe it was necessary to do so before adopting an ECAM.[113]

The OCS challenged the Company's level of market reliance and recommended study of several issues related to the Company's hedging program.[114] Rather, the OCS recommended that if an ECAM were adopted, natural gas hedging and FOTs not be included until its studies were completed.[115]

WRA and Utah Clean Energy ("UCE") concluded that market reliance and hedging issues are fundamentally IRP issues and urged the Commission to require the Company to meet energy efficiency and renewable resource targets and to limit the Company's use of FOTs to meet capacity requirements.[116]

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[112] The DPU's evidence on this issue was based on incomplete information because it ignored physical hedges which the DPU acknowledged were part of the hedging program. Tr. 8/17/10 at 135. The DPU also acknowledged that the purpose of the hedging program was to mitigate the risk of increasing prices and not to beat the market. *Id.* at 122.

[113] Wheelwright Direct Phase II-1 (06/16/10), ll. 808-826; Wheelwright Surrebuttal Phase II-1 (8/10/10), ll. 35-44.

[114] Gimble Direct Phase II-1 (6/16/10), ll. 663-677; Weilgus Direct Phase II-1 (6/16/10), ll. 212-223.

[115] Gimble Direct Phase II-1 (6/16/10), ll. 80-82, 678-689.

[116] Kelly Direct, Phase II-1 (6/16/10), ll. 297-316.

In response to this "evidence," the Company presented facts showing that its current level of market reliance was lower than the level included in its 2008 IRP, was consistent with the level of market reliance included in modeling NPC in the General Rate Case and would provide a benefit of hundreds of millions of dollars to customers in the form of present value revenue requirement.[117] The Company also noted that it had demonstrated in the technical conferences how its hedging program reduces risk of price volatility for customers[118] and presented evidence that rates in the General Rate Case could have been as much as $120 million higher had the Company not hedged and that hedging reduced this exposure to approximately $10 million.[119] Although noting that it is not the proper measure of the effectiveness of a hedging program, the Company provided an accounting that showed that its hedging program had saved customers nearly $305 million from January 2006 through May 2010.[120] The Company stated it has no objection to biennial reviews of its hedging program and would welcome the input of regulators and interested parties on its hedging strategy. It is also willing to consider the use of options in the hedging program, but will only do so after a carefully staged approach in which regulators and interested parties fully consider their costs and benefits.

It is apparent that further study of market reliance and hedging would not result in parties such as the OCS and WRA taking any specific position on acceptable levels and programs. They have now had three opportunities to present evidence on these issues and continue simply to

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[117] Duvall Rebuttal, Phase II-1 (7/20/10), ll. 301-302. The present value revenue requirement savings as a result of the Company's decision to postpone Lake Side 2, which was a major cause of the level of market reliance about which other parties were concerned, is a highly confidential number. It is provided at lines 66, 301-302 and 939 of the highly confidential version of Mr. Duvall's testimony and its derivation is provided in Highly Confidential Exhibit GND-Phase IIA-1R.

[118] Duvall Rebuttal Phase II-1 (7/20/10), ll. 86-91; Bird Rebuttal Phase II-2 (9/15/10), ll. 155-164.

[119] Duvall Rebuttal Phase II-2 (9/15/10), ll. 304-312.

[120] Bird Rebuttal Phase II-2 (9/15/10), ll. 77-79 and Exhibit SAB-Phase II-2-1R.

raise questions rather than provide recommendations. In fact, in response to a DPU proposal that the sharing mechanism be reduced if the Company were able to reduce its FOTs in the future, the OCS argued that it would be inappropriate to set targets for FOTs that might impair the ability of the Company to take advantage of market conditions. Thus, it is apparent that further study of these issues would not result in any objective standards that would assure these parties that an ECAM is in the public interest.

Furthermore, it seems unlikely that the Commission would consider setting objective standards in these areas.[121] As several parties were quick to point out, the Commission only acknowledges IRPs and does not approve them.[122] It is even less likely that the Commission would adopt any specific target for FOTs or mandatory guidelines for a hedging strategy.[123] The DPU effectively argued that the Commission should not set targets that would restrict the Company's ability to respond to the market.[124]

It was undisputed that the issues of the appropriate level of market reliance and hedging strategy are dynamic and will require continuing study and review indefinitely. The Commission has directed the Company to provide further information on both issues in its next IRP filing. Parties may provide responses to that information, and the Commission may provide any general guidance it believes appropriate. However, the Company has demonstrated that customers benefit from its current level of market reliance and hedging strategy and that there is no reason to change these prior to implementation of an ECAM. There will be ample opportunity after the

[121] Tr. 08/17/10 at 203-204.

[122] Tr. 11/2/10 at 332-333.

[123] Tr. 11/2/10 at 332-333.

[124] Wheelwright Direct Phase II-1 (6/16/10), ll. 814-816; Wheelwright Surrebuttal Phase II-1 (8/10/10), ll. 209-214.

ECAM is adopted for customers to provide input on the level of hedging they feel comfortable with given an ECAM.[125]

F. The Company's Proposed ECAM Already Includes an Appropriate Load Growth Adjustment.

The Company's proposed ECAM is calculated on a kilowatt hour basis. That is, base NPC is divided by forecast load and actual NPC is divided by actual load before any ECAM adjustment is made.[126] Therefore, it is undisputed that it already takes into account any growth in NPC attributable to an increase in load.[127]

The DPU and UAE proposed additional load growth adjustments based on increased revenues associated with other aspects of the Company's business. In the case of the DPU, increased revenues attributable to any factor would be offset against increased NPC. In the case of UAE, increased revenues attributable to generation and transmission would be offset against increased NPC.[128] These adjustments are improper because they include increased revenues in an ECAM proceeding, but fail to include increased costs in the proceeding. This is a violation of the matching principle and is an effort to turn what is clearly intended to be a true-up mechanism for NPC into a biased, limited general rate case.[129]

Other parties attempted to justify their proposed load growth adjustments on the ground that load growth adjustments are used in other states and the Company agreed to a load growth

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[125] *See* Graves Rebuttal Phase I (12/10/09), ll. 599-630; Duvall Rebuttal Phase II-1 (7/20/10), ll. 958-965.

[126] Duvall Direct Phase I (11/16/09), ll. 157-163.

[127] Duvall Rebuttal Phase II-2 (9/15/10), ll. 158-159; Higgins Direct Phase II-2 (8/4/10), ll. 386-390.

[128] Higgins Direct Phase II-1 (8/4/10), ll. 92-104.

[129] Duvall Rebuttal Phase II-2 (9/15/10), ll. 163-185.

adjustment in Idaho.[130] However, what these parties failed to note is that load growth adjustments in many other states are typically needed because the ECAM adjustments in those states are based on total dollars of incremental NPC rather than incremental NPC on a kilowatt hour basis. In addition, the Company agreed to a load growth adjustment (and a modest sharing ratio) in Idaho as part of a compromise settlement that allowed the ECAM to go into effect promptly and avoid the extensive litigation that has taken place in Utah and because the other ECAMs in Idaho include these features.[131] On the other hand, Questar Gas's gas balancing account in Utah does not include any similar load growth adjustment or a sharing ratio.

As with other aspects of the Company's proposal, the load growth adjustment already included in its proposed ECAM is fair and reasonable. The load growth adjustments recommended by the DPU and UAE are overreaching and unbalanced. The Commission should approve the Company's proposed ECAM and reject the load growth adjustments proposed by the DPU and UAE.

G. It Is Not Necessary to Address Interjurisdictional Allocations Prior to Adoption of the ECAM.

The allocation of costs among the Company's six state jurisdictions has consistently been a controversial issue before the Commission since PacifiCorp acquired Utah Power in 1989. The Commission is well aware that the Company's different jurisdictions have very different views on this issue. When the Company's financial condition was seriously jeopardized as a result of inconsistent results among the state commissions in the late 1990s and early 2000s, all parties recognized that the public interest was jeopardized and attempted in good faith in a multi-state process ("MSP") to come to a reasonable compromise solution. The solution was the Revised

[130] Higgins Direct Phase II-1 (8/4/10), ll. 323-326, 356-360, 416-427, 433-435.

[131] Duvall Rebuttal Phase II-2 (9/15/10), ll. 201-205; Tr. 11/2/10 at 512, 522-524.

Protocol approved with conditions by the Commission in Docket No. 02-035-04 in 2004. Modification to the Revised Protocol were recently filed with the Commission and a schedule has been established leading to a hearing currently scheduled for March of 2011.[132]

In this context, UAE initially opposed adoption of the ECAM until the interjurisdictional allocation issue was resolved. UAE's argument was that Utah customers' rates do not reflect the full benefit of west-side hydro resources, but that NPC is affected by those resources so that ECAM adjustments could unfairly include costs associated with west-side hydro resources.[133]

In Phase II, UAE proposed that if the ECAM is approved, the Commission ought to essentially adopt the Rolled-In Method retroactively and reduce the rates set in the General Rate Case effective February 18, 2010.[134] Alternatively, UAE recommended that accruals in the ECAM should not be started until rates are effective in the Company's next general rate case, in which the interjurisdictional allocation method will presumably be adjusted.[135] As a third alternative, UAE recognized that the ECAM could be adopted effective February 18, 2010, and that ECAM accruals could be made based on current circumstances until the interjurisdictional allocation is adjusted in the next general rate case.[136] Other parties also argued either that if the ECAM is adopted it should not be effective until the conclusion of the next general rate case or that there should be some adjustment in rates to compensate ratepayers for the difference between the Revised Protocol and a fully Rolled-In Method. However, no party has made any effort to determine the actual impact on customers if the ECAM is adopted effective February

[132] Duvall Rebuttal Phase II-2 (9/15/10), ll. 414-417; Scheduling Order, Docket No. 02-035-04 (Utah PSC Oct. 14, 2010).

[133] Higgins Direct Phase I (11/16/09), ll. 364-386; Higgins Surrebuttal Phase I (1/5/10), ll. 52-83.

[134] Higgins Direct Phase II-2 (8/4/10), ll. 550-568.

[135] *Id.* at ll. 570-574.

[136] *Id.* at ll. 578-583. Mr. Higgins regards this third alternative as "sub-optimal."

18, 2010, but the interjurisdictional allocation method is not changed until the next general rate case.[137]

The Company has submitted uncontroverted evidence that Utah customers do receive benefits from west-side hydro resources. "By carrying reserves on the west-side hydro units, the Company's thermal units can produce more energy to be used to meet load, avoid market purchases, and make wholesale sales, thereby reducing NPC."[138] In addition, it is possible that exposure to the hydro risk in the ECAM results in lower costs to Utah customers if actual hydro generation exceeds the level of normalized hydro generation included in the GRID model.[139] Finally, because rates have been set on the basis of the Rolled-In Method plus 1% in Utah, Utah customers have received some of the benefit of west-side hydro resources.

It is contrary to the stipulation of the parties in Docket No. 02-035-04 for the DPU, OCS, UAE and WRA to argue for a rate change in this docket based on a change in interjurisdictional allocations. The stipulation provides:

> Unless and until any amendments to the Revised Protocol are ratified by the PSCU, for the Company's fiscal years beginning April 1, 2009 through March 31, 2014, for all general rate proceedings, the Company's Utah revenue requirement to be used for purposes of setting rates for Utah customers will be the lesser of: (i) the Company's Utah revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.00 percent; or (ii) the Company's Utah revenue requirement resulting from the Revised Protocol, plus the Rate Mitigation Premium referenced in Paragraph 3, if applicable.[140]

Thus, it is inappropriate for the parties to argue for a rate change based on interjurisdictional allocations unless and until any amendments to the Revised Protocol are ratified by the

[137] Duvall Rebuttal Phase II-2 (9/15/10), ll. 409-410.

[138] *Id.* at ll. 401-406.

[139] *Id.* at ll. 409-412.

[140] Stipulation, Docket No. 02-035-04 (Utah PSC Jun. 28, 2004), Section 4.b

Commission. The Commission will consider amendments to the Revised Protocol in the current proceedings in Docket No. 02-035-04 or, alternatively, in the Company's next general rate case. It has not, however, ratified any change in the Revised Protocol to date.

In addition, it is inappropriate for the parties to urge a retroactive change in rates. Retroactive ratemaking is forbidden except in two exceptional circumstances, neither of which is applicable here. *See MCI Telecommunications Corp. v. Public Service Comm'n*, 840 P.2d 765, 770 (Utah 1992); *EBA Case*, 720 P.2d at 420. Those exceptional circumstances are for extraordinary and unforeseeable expenses or revenues and utility misconduct that result in the utility over earning. *MCI* at 771-774. No party has claimed that either of these exceptions applies in this case, and there would be no basis for doing so. Rocky Mountain Power has regularly been seeking approval of an ECAM since 2001, and the fact that the Company was seeking approval of the ECAM was fully disclosed and known during the General Rate Case. There can be no legitimate claim that rates would have been set differently in the General Rate Case had parties understood that an ECAM might be adopted effective February 18, 2010.

Finally, there is no evidence on the record justifying a move to the Rolled-In Method now or that any problem will result from implementation of the ECAM prior to modification of the interjurisdictional allocation method. However, even assuming Utah customers might possibly be minimally disadvantaged by doing so, it is clear that the possible disadvantage will be very short-lived.[141] Furthermore, a delay in implementation of the ECAM will result in an increase in the size of the deferred NPC balance and in the carrying charges on that balance, imposing a more significant single rate change on customers if combined with other rate changes.[142] The Commission should reject the recommendation of other parties that a retroactive rate change be

[141] Duvall Rebuttal Phase II-2 (9/15/10), ll. 412-414.

[142] *Id.* at ll. 376-378.

implemented or that implementation of the ECAM be delayed until the conclusion of the Company's next general rate case.

H. Other Issues

1. Annual True-ups

Although Wal-Mart argued in Phase I that if an ECAM were adopted it should result in more frequent than annual rate adjustments,[143] by conclusion of the hearing, all parties agreed that if an ECAM is adopted it should be trued-up annually to avoid seasonal fluctuations and provide rate stability. Thus, this issue is no longer disputed.

2. Carrying Cost

The Company originally proposed that the ECAM balance should accrue interest based on the Company's overall cost of capital as determined in its most recent rate case.[144] Other parties recommended that the ECAM balance bear interest at a cost approximately equal to the Company's most recently determined cost of debt.[145] The Company modified its position on this issue, stating that it had no objection to a carrying cost equal to its most-recently determined cost of debt.[146] No party took issue with this proposal. Thus, this issue is no longer disputed.

3. ROE Adjustment

Although no party proposed that the Company's authorized ROE be adjusted in this proceeding, some of the parties suggested that an ROE adjustment would be in order if an ECAM is implemented.[147] Dr. Hadaway presented uncontroverted evidence that all of the companies in the comparable groups considered by witnesses on ROE in the General Rate Case

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[143] Chriss Direct Phase I (11/16/09), p. 10, ll. 10-12.

[144] Duvall Direct Phase I (11/16/09), ll. 179-182.

[145] Higgins Direct Phase II-2 (8/4/10), ll. 668-676.

[146] Duvall Rebuttal Phase II-2 (9/15/10), ll. 241-252.

[147] Chriss Direct Phase I (11/16/09), p. 13, l. 18 – p. 14, l. 3; Tr. 1/12/10 at 157-158.

already have ECAMs in place. Thus, their ROEs already reflect any impact on investors' required returns associated with an ECAM. Requiring a change in the Company's authorized ROE on the basis of adoption of an ECAM would be double counting.[148] This testimony was corroborated by Mr. Graves' testimony in Phase I that "there is no empirical basis for concluding that an adjustment to the cost of capital is required, or if it were, for estimating *a priori* how much of an adjustment would be relevant,[149] and by Mr. Peterson's testimony that the DPU had attempted to measure the impact of adoption of a rate decoupling mechanism for Questar Gas and was unable to measure any effect.[150]

Mr. Higgins' argument that an ECAM reduces financial risk and, therefore, should result in a reduction in authorized ROE, assumes a level of precision in estimating ROE that is not present. As Dr. Hadaway noted, estimation of ROE is simply not that precise.[151] In any event, there is no need for the Commission to address the issue at this time. It would clearly be inappropriate to attempt to determine any adjustment to ROE based on the record in this case. Therefore, the Commission should not condition adoption of the ECAM on an adjustment in ROE in the Company's next general rate case.

4. Frequency of Rate Cases.

The DPU recommended that the Company should be required to file a general rate case every three years while an ECAM is in effect to assure that base NPC does not get too far out of

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[148] Hadaway Rebuttal Phase II-2 (9/15/10), ll. 50-58.

[149] Graves Rebuttal Phase I (12/10/09), ll. 552-560. In fact, Mr. Graves explained why adoption of an ECAM may not reduce risk for the Company's shareholders. *Id.* at ll. 561-590. *See also,* Tr. 1/12/10 at 48-50 (explaining the complexity of the relationship between an ECAM and cost of capital).

[150] In doing so, Mr. Peterson effectively and candidly rebutted his own earlier testimony that adoption of an ECAM might require a reduction in authorized ROE.

[151] Tr. 1/12/10 at 157-158.

line with actual NPC.[152] Other parties adopted this recommendation.[153] The Company agrees that base NPC should be adjusted sufficiently often to assure that an ECAM surcharge or surcredit does not become too large.[154] However, the Company does not believe it is necessary to set an arbitrary schedule for future rate cases. One of the benefits of an ECAM is that it reduces the necessity for frequent rate cases. This benefit should not be eliminated by mandating unnecessary rate cases.[155] In any event, given the Company's current major capital additions, it is likely that general rate cases will be required sufficiently often that this will not be a concern. Therefore, the Company recommends that the Commission not adopt any required minimum schedule for rate cases.

5. Schedule for Annual Filings and ECAM Adjustments.

The Company proposed 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 by December 15 and the adjustment would become effective by February 15 of the following year.[156] The DPU recommended that the Company should file for recovery of the ECAM balance within 30 days after the close of the 12-month ECAM period.[157] The Company responded that it would be unable to file that quickly and that it needed 2 and 1/2 months following the close of the ECAM period to make the filing. The DPU indicated that it was not wedded to its 30-day recommendation and that it would be

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[152] Peterson Direct Phase II-2 (8/4/10), ll. 140-142.

[153] Brubaker Rebuttal Phase II-2 (9/15/10), p. 3, ll. 17-18.

[154] Duvall Rebuttal Phase II-2 (9/15/10), ll. 503-504.

[155] *Id.* at ll. 499-508.

[156] Duvall Direct Phase I (3/19/09), ll. 190-191;

[157] Peterson Direct Phase II-2 (8/4/10), ll. 181-182.

willing to consider a longer filing time if needed by the Company.[158] Other parties expressed concern that a December 15 filing by the Company would not allow sufficient time to review the filing in part because of the holiday season.[159]

The Company's recommended schedule was based on the assumption that the ECAM would be adopted in early 2010 and that a general rate case would be filed in January of 2011 with a rate increase going into effect in September 2011. Given the delay in resolution of this case, it may make sense to adjust the initial filing somewhat. However, the Company urges the Commission not to combine the first ECAM adjustment with the rate adjustment in the next general rate case. Furthermore, because the Company has agreed that ECAM rate adjustments may be made on an interim basis while the DPU completes its prudence review, it is reasonable for the interim adjustment to be made within 60 days of the Company's filing. An interim rate adjustment was made under Questar Gas's gas balancing account within 37 days of that utility's most recent filing.[160] This time period is typical for interim rate adjustments for Questar Gas under its gas balancing account. 60 days should be more than adequate to initially review the Company's ECAM filing even if a week to ten days is lost to the holiday season.

6. Rate Spread and Rate Design.

The Company explained how ECAM rate adjustments would be spread in its testimony filed with its application on March 16, 2009. The Company proposed to spread the ECAM adjustment based on an equal cents per kilowatt hour basis after adjusting for voltage level losses across all customer classes, except time of day Schedules 6A, 8, 9 and 9A. The Company proposed that the equal cents per kilowatt hour applied to Schedules 6A, 8, 9 and 9A be shaped

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[158] Duvall Rebuttal Phase II-2 (9/15/10), ll. 509-517.

[159] Brubaker Rebuttal Phase II-2 (9/15/10), p. 3, ll. 22-24.

[160] *See* Docket No. 10-057-09 (Application filed June 24, 2010, rates effective August 1, 2010).

to mirror the structure of the time of day base energy charges for those schedules, so that there would be separate on-peak and off-peak adjustment rates by season. [161]

No party challenged this proposal until UIEC filed rebuttal testimony in Phase II-2 on September 15, 2010, 18 months later.[162] In fact, rather than challenging the Company's proposed rate design, UAE's witness, Mr. Higgins, who also represents large industrial customers, agreed that it was reasonable.[163]

Regardless of the lateness of UIEC's challenge to the rate spread and rate design proposal, it is without merit. UIEC argued that the rate design did not reflect seasonality of costs and that it "smeared" together deviations among customer classes by month.[164] A possible solution, suggested by UIEC's witness, Mr. Brubaker, was to break the year into more segments and to keep track of deviations from base NPC by this greater number of segments.[165] In cross examination, UIEC implied that deviations might also be tracked by customer class. As Mr. Griffith testified, the ECAM surcharge or surcredit is applied proportionally to usage based on time and season of usage. Therefore, customers who use power during the peak will be exposed to higher ECAM surcharges than customers who do not. This is reasonable.[166] While it is possible to make endless refinements to a rate spread and rate design, doing so results in undue

[161] Griffith Direct Phase I (3/16/09), ll. 45-47, 54-67.

[162] UIEC claimed it did not raise the issue in direct testimony on ECAM design issues filed on August 4, 2010 because it needed responses to outstanding data requests.[162] However, on cross examination, Mr. Brubaker admitted that the Company's responses to the data requests were timely and that the questions had not been sent to the Company until July 26, 2010, only nine days before the testimony was due. Tr. 11/2/10 at p. 442, ll. 13-18.

[163] Higgins Direct Phase II-2 (8/4/10), ll. 121-124 ("I also concur with the rate design proposal presented by RMP witness William R. Griffith that would differentiate and ECAM adjustor charge by voltage and time-of-day, as applicable.").

[164] Brubaker Rebuttal Phase II-2 (10/13/10), p. 10, ll. 6-14.

[165] *Id.* at p. 11, ll. 4-10.

[166] Griffith Surrebuttal Phase II-2 (10/13/10), ll. 34-38.

complexity with little benefit. The Company's proposed rate spread and rate design is reasonably simple and is fair.[167] UIEC's untimely challenge was insubstantial and should be ignored.

IV. CONCLUSION

Rocky Mountain Power's current pattern of substantial under earning is largely attributable to the fact that actual prudent NPC is far in excess of the amount included in rates. The overwhelming evidence in this case shows that it is time for Utah to adopt an ECAM (as all other non-restructured states already have) so that the Company's rates are truly just and reasonable for the benefit of both the Company and its customers. As structured by the Company, the ECAM will not shift risk to customers and will actually eliminate one risk to customers—the risk of over-recovery of NPC. The ECAM proposed by the Company is simple, balanced and straightforward. Other parties' proposals for a dead band and 70-30 sharing mechanism are unwarranted, extreme and inconsistent with the need for an ECAM. The Company respectfully recommends that the Commission approve its proposed ECAM to be effective on February 18, 2010 on a pilot program basis through 2013.

[167] Tr. 11/01/10 at 191-192, 197.

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Respectfully submitted,

ROCKY MOUNTAIN POWER

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CERTIFICATE OF SERVICE

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