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** **Exhibit No. DPU 3.0SR** **Surrebuttal Testimony for Phase II, Part 2, by** **Charles E. Peterson**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Surrebuttal Testimony for Phase II of

Charles E. Peterson

R E D A C T E D

October 13, 2010

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Surrebuttal Testimony of Charles E. Peterson

I. INTRODUCTION

Q. Please state your name, business address and title.

A. My name is Charles E. Peterson; my business address is 160 East 300 South, Salt Lake City, Utah 84114; I am a Technical Consultant in the Utah Division of Public Utilities (Division, or DPU).

Q. On whose behalf are you testifying?

A. The Division.

Q. Are you the same Charles E. Peterson who filed direct and rebuttal testimony for the Division in Phase I and Phase II of this matter?

A. Yes.

Q. What is the purpose of your testimony in this matter?

A. I respond to the Phase II Design rebuttal testimony filed by the Parties.

Q. Please outline your surrebuttal testimony.

A. First I will make comments on the rebuttal testimony of the Company's witnesses. I will follow that with comments on the rebuttal testimony of witnesses for the Office, UAE, WRA/UCE, and UIEC.

I do not comment on all of the ideas and statements made by the various witnesses. Silence on a given subject does not imply that the Division necessarily agrees with the witness on that subject.

II. COMMENTS ON REBUTTAL TESTIMONY.

PacifiCorp/Rocky Mountain Power Witnesses

Q. Please outline principal points in the PacifiCorp witness's testimonies that you wish to respond to.

A. The principal points, or issues, raised by Company witnesses include dead bands and sharing mechanisms; load growth adjustment factors; carrying charges; renewable energy credit (REC) revenues; deferred net power costs (NPC) and REC revenue balances; auditing; hedging; and front office transactions (FOTs).

Some issues discussed by Company witnesses were dealt with in my rebuttal testimony, including the exclusion of certain costs such as natural gas fuel and hedging costs from the ECAM; hydro generation and interstate allocation; and return on equity (ROE).[1] I do not

[1] Company witness Dr. Hadaway incorrectly understands that, in a footnote, I made a recommendation to the Commission to significantly reduce the Company's authorized ROE if an ECAM were adopted. I only suggested

discuss these issues further here other than to state that I stand by my direct and rebuttal testimony regarding these issues.

The Company (primarily through its witness, Dr. Karl McDermott) repeats its contention that an ECAM is justified through the claimed absolute right to recover all "prudently incurred costs." I discussed this contention in testimony in Phase I of this Docket.[2] The Division remains unpersuaded by the Company's argument.[3]

Q. How do you respond to the Company's comments regarding dead bands and sharing mechanisms?

A. The Company opposes dead and sharing bands essentially on the basis that it deserves to recover all of its "prudently incurred costs." Mr. Duvall also argues that the dead bands and sharing bands do not provide proper incentives for the Company and that regulators should solely rely on prudence reviews to make sure the Company is acting "properly."[4]

The Division has previously made its position clear. In general rate cases the Company has indeed been given the opportunity to recover its prudently incurred costs and to earn a fair return on its investments through the rates set in a general rate case. After rates are set by the Commission, the Company's obligation is to provide service and manage its costs. The

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that the Division would consider accepting the Company's proposed ECAM if the Company were willing to accept a significantly lower ROE.

[2] For examples see, Charles E. Peterson, Direct Testimony for Phase I, Docket 09-035-15, November 16, 2009, lines 308-338; 410-416; 549-562; and 584-591.

[3] Dr. McDermott focuses only on the potential for the Company to not recover all of its NPC, although with any sort of ECAM, the Company is better off than with the status quo. He ignores that, on the flip side, the Company may collect more than its costs. He also seems in places to conflate total NPC with the difference between actual NPC and forecast NPC; this appears to be a conceptual error which could result in misunderstanding of my testimony. (For this latter issue see, Dr. McDermott Rebuttal Testimony, lines 61-63, 72-79).

[4] Gregory N. Duvall, Rebuttal Testimony, September 15, 2010, pp. 4-6.

Company is already being compensated to assume normal business risks, part of which is variability in costs. The Division agrees that there may be a case for providing some sort of ECAM but not at the expense of removing incentives for the Company to prudently manage its business, or at the expense of removing business risks for which the Company is being compensated. I discuss the prudence review issue below.

Q. The Company rejects the Division's load growth adjustment mechanisms in the ECAM. Does the Company present convincing arguments against them?

A. No. Company witness Mr. Duvall mentions one scenario where he claims that Utah customers might be unfairly advantaged, i.e. where revenues in a state other than Utah rise significantly over expectations, but all else remains the same. In this situation, the higher system revenues would offset NPC and somehow give Utah ratepayers an unfair advantage. He concludes by stating that there might be unintended consequences.[5]

This analysis is misplaced.

First Mr. Duvall apparently misunderstands the purpose of DPU Exhibit 3.3 and the use of Form EIA-826. Generally, Exhibit 3.3 was used to reconstruct the value of differences between forecast and actual load by using the average price per MWh derived from Form EIA-826. The use of Form EIA-826 was necessary since the Division lacked the actual revenue difference figures. The use of DPU Exhibit 3.3 was to derive reasonable estimates for DPU Exhibit 3.2 which was an attempt to give some sense of what the results of the Division's proposed ECAM *might* have been had an ECAM been in place historically. In the

[5] Duvall, Op. Cit., lines 231-240.

operation of the actual ECAM, actual Company numbers would be used with no reference to Form EIA-826.

Second, the rationale for an ECAM is that the Company cannot control its NPC on a *system* basis. Higher revenues in another state implies that the Company has more money to cover NPC costs, whether higher than expected or not (e.g. in the case of an unexpectedly generous rate increase in the other state). Mr. Duvall's example suggests that he would, rather, punish Utah ratepayers because of the higher than expected revenues in another state and possibly allow the Company to earn windfall profits as a result.[6]

I did conceptualize the Division's proposal as starting with system NPC and revenues and allocating a percentage of the differences to Utah. This conceptualization was based on the system nature of NPC and the need to do an allocation as opposed to a direct measurement of Utah NPC. One reason for creating a pilot program is for the detection and correction of significant unintended consequences. While Mr. Duvall's example is possible, it is unlikely since I believe that most often there will be offsetting factors coming from either other states or within Utah. If the Commission is concerned about this possible unintended consequence

[6] A rate increase in another state should only reflect a truing-up of revenues to costs in that state and should not be a consideration in the Utah ECAM. In the event that the demand for power in another state was significantly above forecast also implies that NPC in that state would be higher as well. The Company higher revenues collected would partially, if not totally offset the higher costs. These changes would also appropriately shift interstate allocations to the state with the higher load demand. This shift in interstate allocation would mitigate any alleged "unfair advantage" that Utahns would receive as a result of the ECAM. But more to the point, there are two possible situations given Mr. Duvall's scenario: either the higher revenues partially covered the higher NPC, or the higher revenues were equal to or greater than the higher NPC. If the first case holds then there is excess NPC created in the other state, that if not mitigated by interstate allocation changes would result in Utahns paying a greater than fair share of the higher NPC. In the second case, again assuming that interstate allocation changes did not neutralize the effects, Mr. Duvall would allow the Company to double recover its costs; once from the rate payers in the state with the higher revenues, and then from Utah customers through its ECAM since the ECAM would focus only on NPC, which was already paid for by customers in the other state. This would indeed be an "unintended consequence" of the Company's proposed ECAM if there was no mitigation for revenues.

suggested by Mr. Duvall, then one solution would be to convert all revenues and net power costs to Utah figures first and then apply the ECAM formulae. However, I believe the original formulation based upon system numbers is more straight forward.

Q. Does the Company accept the Division's proposal for the carrying charge on ECAM balances?

A. Yes. Company witness Gregory N. Duvall states that the Company is willing to accept a carrying charge equal to the Company's long-term debt.[7]

Q. The Company argues again for renewable energy credits (RECs) to be included in the ECAM. Have Company witnesses presented anything new or compelling in their arguments?

A. No. But to recap some of my comments, RECs are not an appropriate part of the ECAM since they relate to revenues received for an intangible attribute of certain generation properties recently created by government action and do not represent a power "cost" incurred by the Company. Furthermore, the Company is already recovering the costs it has incurred for the construction of those generation plants including a fair return on its investment; customers have already paid for the RECs coming from those assets and therefore should keep all of the revenues. In the case where the Company purchases renewable power and acquires the RECs from that source because it paid a premium for that power in order to get the RECs, then the Division would support that the Company keep the RECs in that instance to offset NPC.

[7] Duvall, Op. Cit., lines 248-252.

Q. Do you agree with the Company's proposal regarding the deferred balances of REC revenues and NPC?

A. No. I have dealt with this question in my rebuttal testimony. The Division believes that these deferrals should be dealt with separately, so that any ECAM can be started with a "clean slate." Particularly in the case of the deferred RECs, they represent revenues that possibly should have been included in the previous general rate case, but were not.

Q. The Company witnesses suggest that auditing and prudence reviews are all that's necessary to make sure that the ECAM is properly run. Do you agree with that position?

A. No. While auditing and prudence reviews are one tool regulators can use to assure compliance with the public interest, regulators should not give up other tools that they can use to assure compliance such as constructing proper incentives that will operate independently of audits and prudence reviews.

Q. Company witness Stefan Bird provides lengthy testimony regarding the Company's hedging program. Do you have any comments regarding this part of his testimony?

A. The Division appreciates Mr. Bird's extended explanation of what the Company considers to be encompassed by its hedging program. As has been noted previously, there has been some confusion regarding what was meant by the Company's "hedging" activities, i.e. sometimes hedging seemed to refer to the swap contracts alone and other times it seemed to have other components that were not well defined. While not answering all of the Division's questions, this testimony is helpful.

Q. On lines 94-95 of his rebuttal testimony, Mr. Bird suggests the Division's recommendation of sharing bands and dead bands was based upon its understanding of the results of the Company's hedging program. Is this correct?

A. No. The Division's proposal for a dead band and sharing bands has little to do with the Company's hedging program and much to do with maintaining proper incentives for the Company to prudently manage its net power costs. While concerned about the Company's hedging program (and front office purchases), as Division witness Douglas Wheelwright and I have previously made clear, the Division's concern does not rise to the level of taking somewhat drastic action such as excluding natural gas hedges and front office transactions from the ECAM as proposed by the Office.[8]

Q. Mr. Bird states that the hedging is done to reduce the volatility and exposure to a price increase in natural gas or a price decrease in electricity. Does that agree with what the Division has concluded?

A. Yes. This is exactly what the Division has said in testimony and identifies as one of its primary concerns about the Company's hedging program.[9] While the hedging program protects the Company from increases in the price of natural gas there is no mechanism for the Company to take advantage if there is an expected or significant reduction in the market price of natural gas or an increase in the price of electricity. For example, the Company's current hedging program contains no guidelines or mechanisms to unwind its current positions if those positions begin to turn sour. The Division believes that the Company's

[8] See Daniel E. Gimble, ECAM Design Direct Testimony for the Office of Consumer Services; Docket No. 09-035-15, August 4, 2010, pp. 9-12.
[9] Testimony of Douglas D. Wheelwright, Docket No. 09-035-15, June 16, 2010, e.g. lines 695-761.

hedging program should have a contingency plan or other mechanism in place that would allow the Company and ratepayers to take advantage of changing market conditions should they develop.

Q. Do you agree with Mr. Bird's assessment that the current hedging program has protected the customers from the risk of an unfavorable price movement in the commodity?

A. That depends on how you look at the issue. In a general rate case, the rates are determined based on the forecast load and the forecast net power cost. The projected NPC includes the commodity pricing based on the forward price curve at that point in time. Since customer rates are set based on the forecast, any variation between the actual NPC and the forecast will affect the Company and not the customers under the current regulatory structure. The hedging program is designed to lock down the prices that will likely be used in the forecast test year. From the perspective of the Company, in Mr. Duvall's rebuttal testimony, he indicated that without hedging NPC "might have been $120 million higher"[10] in the last general rate case. He states that by securing these prices in advance, the Company has been able to keep the commodity portion of NPC below the spot price and pass that saving on to the customers.

However, that begs the question of what the Company's forecasts would have been in a general rate case had it not been hedged. It seems likely that it would simply have been based upon the Company's then current forward price curve estimate without the gains or losses

[10] Duvall, Op. Cit., lines 304-312. Of course, Mr. Duvall also does not mention that, in the absence of swaps, NPC in the 2008 rate case could have been $192 million lower. 08-035-38, Exhibit GND_1SS.

from the hedging contracts (e.g. gas and electric swaps) as shown in Company witness Gregory N. Duvall's exhibit titled PacifiCorp _UT GRC NPC - June 2010 GOLD _2009 05 29 in the last general rate case (Docket No. 09-035-23). In other words, there may have been little or no change for ratepayers.

Q. Do you agree that the effectiveness of the hedging program should not be measured by gains and losses?

A. I agree that the gains or losses on the Company's hedging positions should not be the sole criterion to measure the effectiveness or success of the Company's hedging strategy. However, there must be some measurement or guideline to determine if this or any program is producing the desired results and if it has been effective in achieving those results. Hedging is done by the Company to secure prices in the future and is based on forecasts and projections. As indicated by the Company, the purpose of the Company's hedging program is not to beat the market but to reduce the volatility in prices. The Company's argument that but for the hedging program forecast net power costs may have been $120 million higher in the last rate case does not address the stated purpose of the hedging program to reduce volatility and, therefore, is irrelevant to the issue at hand. As I have pointed out previously, for ratepayers, prices are constant between rate cases regardless of the level set by the Commission. The effectiveness of this or any program should be measured against the actual results to determine the accuracy of the projections, or have a verifiable explanation for any deviation of the actual from the forecast that is outside an accepted range. Only after a review and assessment of the results can it be determined if any adjustments are needed. If the Commission and the Company determine that the primary goal is reduced volatility, then measurements and standards should be in place to measure the volatility compared to the market prices. The results should be periodically reported. However, as I and Mr. Wheelwright have stated in previous testimony, eliminating volatility is not the only possible purpose of hedging and the Division believes that the Company should be provided with guidance by the Commission as to the purpose of hedging going forward.

Another measurement would be to test whether, over time, the Company's NPC forecasts are unbiased, i.e. that the forecasts are high roughly as often as they are low. Another way of putting it is that the gains and losses should in the long run net out close to zero. Persistent losses, or gains, from hedging would suggest that the hedging strategy would be in need of adjustment.

Q. Do you agree that the fixed price physical transactions were not included in your testimony?

A. Yes. As stated by Mr. Bird, the information relating to the fixed physical transactions was not provided to the Division. Following the August 17^{th} hearing, the Division initiated a data request to obtain the settled physical transactions for both natural gas and electricity. Confidential DPU Exhibit 3.1SR is a summary of the monthly settled values for swaps and physical contracts for 2006 through July 2010. This information is from a historical perspective and looks at actual settled values of swap and physical contracts. It is interesting that out of the 55 months represented in DPU Exhibit 3.1SR, physical electric hedges have been positive in 49 months or 89 percent of the time. Given the Company's stated purpose for hedging, the percentage of positive months in the future would be expected to approximate 50 percent, with runs of negative months being possible.

The Division remains concerned that the definition of the Company's hedging program is ill-defined. For example, as stated in the attachment to Mr. Bird's rebuttal testimony, forward purchases of electricity and natural gas to a lesser extent, at fixed prices and volumes are considered hedges. Gains from these forward physical purchases are used to offset losses in electric and natural gas swaps to demonstrate some of the positive benefits of the hedging program. It remains unclear to the Division exactly how the Company implements physical electricity purchases as part of its hedging program. Furthermore, the Company does not include other "obvious" physical hedges such as coal stockpiles. Indeed one could argue that spot market balancing purchases are a hedge against owning too much generation capacity. The point being made is that the Commission needs to review what is considered to be within the hedging program and how the hedging program will be evaluated for its effectiveness in meeting the Commission accepted goals of the program.

Q. Were you able to determine anything from the additional data provided?

A. Yes. Including the physical contracts provides a significant benefit to the hedging program and offsets the losses associated with the swap transactions. Since the beginning of 2008, there have been very few physical natural gas transactions with the majority of the physical activity coming from electricity. However, the information provided for YTD 2010 indicates a reduction in the volume and dollar amount of the physical electric contracts.

Q. Is there another way to look at the value of these contracts other than the settled values?

A. Yes. Only after settlement, after the forecasted transaction occurs, are contracts recognized as income or expense. Prior to the settlement date, contracts are recorded on the Company's financial statements as either assets or liabilities and are stated at the fair value as of the reporting date. The fair value is determined from price quotes for identical contracts or from internal pricing models using the Company's forward price curves. The contract value is also a function of the commodity price, relative volatility, counterparty creditworthiness and duration of the contract. The net unrealized gain or loss associated with the interim price movements are recorded as net regulatory assets and liabilities.

Confidential DPU Exhibit 3.2SR is a reconciliation of the unrealized loss reflected in the Company financial statements for 2008, 2009 and the first 6 months of 2010. While the majority of the change in fair value is tied to the contracts identified by name, the value of the fixed forward and swap transactions is identified in the center of the report. This information also indicates a reduction in the fixed physical transactions in 2009 and through June 2010. Since DPU Exhibit 3.2SR is based upon "mark to market" accounting, the large deficit between swaps and fixed forward contracts so far in 2010 may presage the reversal of the run of positive amounts. Additionally, as indicated by the size of the dollar amounts set forth on DPU Exhibit 3.2SR; there is potentially a lot of money at stake.

Q. The Hermiston contracts have been indentified in Exhibit 3.2SR. Have you been able to determine if these contracts are "in the money," that is the contract price is better than the current market price, as has been represented?

A. Yes. The information provided in response to DPU data requests 1.25, 5.3 and 11.3 clearly identifies the value of the Hermiston contracts as of year-end 2008, 2009, and YTD 2010. In response to DPU Data request 11.5, the Company clearly indicated that the net of both the custom and the transportation portions should be included to evaluate this contract. While it has been verbally represented by Company representatives that these contracts remain in the money, the information provided indicates mark to market losses of [redacted] as of December 31, 2009 and [redacted] as of June 30, 2010.

Q. Have you been able to verify the Company's position that there is an offset between the gas and electric positions or an offset of swaps and fixed physical contracts?

A. In DPU Exhibit 3.1SR there is some offset between the gas and electric swaps. While this is not a dollar for dollar change between the two commodities, there is a partial offset. When the physical contracts are included, the net has been positive 43 of the 55 months under review. If "hedging" includes swaps and fixed forward contracts, then for calendar years 2008 and 2009 the Company was in a net positive position. Furthermore, the *combination* of electric and gas physical contracts were profitable in 48 of the 55 months under review. By contrast, the items identified as "derivatives" in the Company's SEC financials, look at the current value of the existing contracts and show a different picture of the Company's "hedging program." If "hedging" is extended to all "derivatives," then the Company is badly "under water" (negative) and potentially raises questions about the Company's policies and practices going forward.

Looking at just the swaps and the fixed forward contracts, in DPU Exhibit 3.2SR, the mark to market value indicates that the fixed forward contracts did offset the loss on swaps for 2008 and 2009. Year to date 2010 indicates only a partial offset of the loss on swaps. In any case DPU Exhibits 3.1SR and 3.2SR highlight the problem of carefully defining what is, or will be, defined as the Company's hedging program going forward.

Q. In reference to the hedging activities of the Company, do you have any other concerns with the proposed ECAM?

A. One of the challenges of the proposed ECAM is the prudence review. In a general rate case the NPC is estimated based on forecast load and anticipated commodity prices in a future test period. Based on these forecast variables, the rates are established and determined to be just and reasonable. At some point in the future the contracts will mature and the actual price differential of the transactions will be determined. If there has been a significant change in the market conditions between the time these contracts were initiated and the settlement date, there may be parties that may challenge these decisions and may believe that entering into these contracts was not prudent. At that point it will be difficult for parties to challenge these costs because the Commission, for example in a comprehensive rate settlement may have already approved some or all of the hedging transactions, so that the Company will plausibly argue that these rates were determined to be just and reasonable and they should not be challenged on this issue. There should be a protection for both the Company and for the intervening parties to review these decisions. Having a Commission-approved hedging plan or strategy in place would provide such protection.

Q. The Company witnesses make further comments regarding front office transactions. Do you have a response to these comments?

A. Yes. I will comment on Mr. Bird's complaint that the Division's proposed ECAM would create "perverse incentives" for the Company regarding FOTs.[11] This comment is interesting for two reasons. First, all the Division is proposing through 2015, at least, is that the Company meet the goal it has itself set in its 2008 IRP Update. Second, the Division has made it clear that the Company and intervenors can propose changes to the ECAM, including the handling of FOTs, before any changes to the sharing band percentages go into effect. For example, if subsequent IRPs indicate a significant change in the Company's least cost/risk FOT position in the coming years, and those new positions are supported with adequate evidence or analysis, then the Company can apply for changes in the target FOT levels or goals. The Division's proposal for a treatment of FOTs in its ECAM proposal is carefully drawn and circumspect.

Q. Does the Division necessarily require that its proposed ECAM be delayed until after the next rate general rate case?

A. No. While the Division's proposed ECAM requires that the Commission determine an annual forecast of net power costs and revenues, it does not necessarily imply that those forecasts have a beginning point at the end of the rate case. For example, if the Company files a general rate case in January 2011, as it has indicated it is planning to do, assuming the

[11] Bird, Op. Cit., lines 217-221.

Commission has previously approved the Division's ECAM in this Docket, then the accounting tracking of the NPC differentials based upon Commission approved forecasts could begin on January 1, 2011. The Company could apply for rate relief under the ECAM sometime in early 2012. The Division considers it to be best if the ECAM were set up to operate on a calendar year, with any fiscal (calendar) year-end accounting adjustments included in the process.

Q. Do you have any final comments regarding the Company's ECAM position?

A. The issues raised by the Company come down to this: actual net power cost has been different than the Company's forecasted net power cost. Unfortunately for the Company, actual net power cost has usually been higher than the Company's forecast. The Company itself has made a decision to run rate cases based upon forecast test periods, which necessarily rely upon forecasts made by the Company. It is a cliché that forecasts are almost always wrong to some degree, and that's a risk the Company (as well as other stakeholders) always faces when using a forecast test period. With its proposed ECAM, the Company management is essentially transferring to ratepayers all of the risks associated with the Company's own NPC forecasts and the management of its NPC accounts. Suggestions that the Company maintain some responsibility for its own decisions regarding NPC, as the Division and other intervenors in this Docket have tried to do, are met with considerable resistance by the Company. The Division believes that the Company properly needs to keep some responsibility for its own decisions, including its forecasts, and not hold itself harmless through an ECAM or similar mechanisms. The Division's proposed ECAM continues to give responsibility to the Company for its NPC operations and forecasts, while at the same time recognizing that there may be significant volatility in costs that remain outside of management control.

Daniel Gimble/Office of Consumer Services

Q. Mr. Gimble says that the Company (or ratepayers) would receive 68.6 percent of the "actual net power costs that fall above and below the 2% dead-band."[12] Is this correct?

A. No. The 68.6 percent figure is the percentage collected above or below the zero line (i.e. the center line of the 2 percent dead band range, or where NPCa-NPCf=0)[13] by the Company or ratepayers, respectively, once the Company's NPC is determined to be outside of the dead band range.

Q. Do you still maintain that this is the correct formula?

A. Yes. There are different ways one might formulate the calculation. Given the complication of the net revenue difference in the formula, for simplicity the Division elected to "shrink" all of the terms by 2 percent to reflect the dead band and then multiply the net of the net power cost and the revenue adjustment by the amount of the sharing percentage. The formula operates symmetrically so that ratepayers and the Company would be benefitted equally assuming net power cost forecasts are unbiased over time.

Q. Mr. Gimble indicates that the revenue adjustment portion of the formula could "push" the net amount back into the dead band range, is this correct?

[12] Gimble rebuttal testimony, lines 66-67.
[13] NPCa is actual net power costs, NPCf is the forecast net power costs.

A. Yes. However, once the dead band is "breached" the Division would proceed to apply the formula and add whatever the result is to the balancing account. Given the effect of the revenue adjustment, the sign of the amount added to the balancing account could reverse from the original NPCa-NPCf calculation.

Q. Mr. Gimble disagrees with the inclusion in the Division's ECAM proposal of a recovery band wherein if the Company's actual NPC differs by more than 30 percent from the forecast, then 100 percent recovery of the extreme differences greater than 30 percent is the result. Do you have any comments?

A. Yes. As Mr. Gimble points out, such an extreme difference will likely have the attention of the Company and regulators before any regular application of an ECAM true-up. The primary concern of the Division is that under existing mechanisms, absent an ECAM, it is difficult for the Company to receive recovery retroactively. In a crisis, such as would likely be underway should the actual NPC vary by hundreds of millions of dollars, the Company could be in a significant financial hole before the regulatory process, absent an ECAM, would act to stop losses going forward. Receiving relief for such a situation would be extraordinary under the current system. It may be paramount to the Company's creditworthiness and near-term financial viability that regulatory support is immediately and automatically available. In this context it is appropriate that regulators show support for the Company during a crisis which would help to sustain the Company's ability to continue to get credit during the crisis and otherwise reduce its financial stress. This is one of the reasons the Division supports a properly constructed ECAM.

Q. Mr. Gimble disagrees with the Division's proposal to have targets for front office transactions and the Company's hedging proposals. Do you have any comments?

A. Yes. As mentioned above, the Company and intervenors may propose changes to the targets and the sharing percentages proposed by the Division based upon the results of the Division's proposed ECAM pilot period, the Company's compliance with the proposed conditions recommended by the Division, and other factors and conditions that are apparent at the time of the Commission's review of the ECAM pilot program. The intent of the Division's proposal was to provide direction within the ECAM for the FOT and hedging issues raised by the Office in this Docket. The Division has already recommended that parties could and should pursue the FOT and hedging issues independently of the ECAM docket. At such time as the Commission resolves the FOT and hedging issues, adjustments can be made to the NPC included for true-up in the ECAM.

Q. With respect to FOTs, Mr. Gimble questions the part of the Division's proposal in which it suggests that the Company complete a study of the risks and benefits of its FOT program in order to obtain an adjustment to the sharing percentages in the ECAM. He also wonders how this differs from the Commission's order to provide additional analysis of FOTs in the Company's Integrated Resource Plan. Do you have additional comments regarding the Division's FOT proposal within the ECAM?

A. Yes. First, the 2015 timeframe is essentially the earliest time the Company will have substantial additions to its generation capacity online. Before that time, the Company is basically "locked in" to FOTs to cover its load beyond its current owned capacity, so little change in the currently projected level in FOTs can be expected much before 2015. Because of this, the Division proposed the 2015 timeframe for the FOT study.

Second, with respect to the Commission's IRP order, the Division is requesting a study that goes beyond market depth and liquidity, requiring the Company to present a detailed analysis of the costs and benefits of the levels of FOTs the Company expects to maintain beginning in 2015.

Q. Mr. Gimble proposes including REC revenues in the ECAM. What is the Division's position?

A. As the Division has explained earlier, RECs are not an appropriate part of the ECAM since they relate to revenues received for an intangible attribute of certain generation properties recently created by government action and do not represent a power "cost" incurred by the Company. In the Division's opinion, REC revenues are outside the scope of this Docket.

Q. Mr. Gimble believes it is inconsistent to include wheeling costs in an ECAM and exclude wheeling revenues. Do you agree with him?

A. No. Wheeling revenues are rents the Company receives on its transmission system, whereas wheeling costs are costs incurred by the Company to deliver power to its retail customers and are properly included as part of NPC. Conceptually, wheeling revenues and wheeling costs are not related to one another. Naturally the Company would not oppose wheeling revenues being included in an ECAM since, especially if there are sharing bands, the Company could keep some of those revenues whereas currently they simply offset the Company's retail revenue requirement. Thus, including wheeling revenues in an ECAM is a potential windfall for the Company.

Kevin Higgins/UAE

Q. Similar to Mr. Gimble, Mr. Higgins disagrees with the Division's proposals to (1) change the sharing band percentages in the future if the Company meets certain criteria, and (2) move to a 100 percent sharing percentage if NPC differences hit extreme levels. Do you have any further comments on these issues?

A. No. I responded to these disagreements in discussing Mr. Gimble's rebuttal testimony.

Nancy Kelly/WRA/UCE

Q. Ms. Kelly asserts that the Division's ECAM proposal does not comply with the criteria the Division set forth for an appropriate ECAM in Phase I of this Docket. How do you reply to this assertion?

A. In my direct testimony I discussed in detail the relationship between the five criteria set forth in my Phase I direct testimony and the Division's proposed ECAM in Phase II. Ms. Kelly believes the Division satisfied only one of its five criteria—that in its proposed ECAM the Division offsets incremental NPC with incremental revenue. For example, Ms. Kelly insists that the dead band and sharing band percentages violate the Division's first criterion of not reducing management's incentive to pursue a least-cost, least-risk strategy. I maintain that the sharing percentages keep those management incentives intact. However, Ms. Kelly believes that the proposed sharing band percentages, even though they are identical, at least initially, to her own proposed sharing percentages, weakens management resolve to pursue efficiency and a least-cost, least-risk strategy apparently to the point that they are incented to pursue something else. The Division disagrees with this conclusion as being unsupported. The fact remains that the Company continues to have substantial money at risk.

Ms. Kelly disagrees with the satisfaction of the second criteria that the Company should pursue an owned resources strategy, apparently because the Division's proposed ECAM does not guarantee the construction of the types of resources she prefers. This is true. This is commented on further below. She does not believe that the risks shifted to ratepayers are fair, even though, again a main feature of her ECAM proposal is the same sharing bands the Division proposes. With respect to the Division's final criterion, I admitted in my direct Phase II testimony in this Docket that upon further consideration the Division determined that strict adherence was not likely in the public interest since it could produce perverse incentives. In part of her rebuttal testimony (lines 234-241) she seems to agree, but only to the extent that there may be incentives created against her preferred sources of energy. Again, I deal with this issue further below. I argued in my Phase II direct testimony that the Division was compliant with its stated criteria. Ms. Kelly's rebuttal arguments to the contrary are not persuasive.

Moreover, while Ms. Kelly points out that an ECAM may be a benefit to the Company's shareholder by reducing the uncertainty of the Company's cash flows, i.e. reducing risk versus the status quo, she seems to forget that ratepayers may also benefit by a return of any excess payments they made for NPC—something that does not occur under the status quo.

Q. Ms. Kelly criticizes you for basing your proposed FOT adjustments on the Company's 2008 IRP Update rather than the 2008 IRP. Would the 2008 IRP have formed a better basis for what you are proposing?

A. No. The 2008 IRP Update, for whatever flaws Ms. Kelly believes it contains, represents the latest business plan of the Company. As such it is the most recent plan that Company management, presumably, is committed to implementing (should the forecast assumptions remain stable through the end of the forecast period). At a minimum, the Company cannot disagree with its own stated goals. By the fact of the existence of the Update and business plan that differs from the 2008 IRP, the 2008 IRP is now obsolete in the view of the Company's management. Therefore it appears to make no sense to try to base anything going forward on the earlier plan. As I stated, if the Division's ECAM proposal is implemented by the Commission, at the end of the pilot period, all aspects of the ECAM will be open for re-evaluation including even the continuance of the ECAM. Even within the pilot program if something is clearly amiss, there is no reason a party could not move to have something corrected.

Q. Ms. Kelly is concerned that the Division's proposed ECAM may not provide the incentives to the Company to acquire the types of generation plant she prefers. Do you share her concern?

A. No. While it is conceivable that the ECAM will have some small influence on the type of plant the Company acquires, I have argued before that the Division is unpersuaded that the ECAM will have a significant effect on the type of generation acquired by the Company.

There exist significant other forums as well as public and political pressure for pursuing the type of plant Ms. Kelly appears to want.

<u>Maurice Brubaker/UIEC</u>

Q. Mr. Brubaker lists sixteen "findings and recommendations," do you plan to comment on all of them?

A. No. Many of Mr. Brubaker's points are similar to points made by others and my responses will not be repeated here. In addition, Mr. Brubaker repeats recommendations such as not implementing the ECAM until issues regarding the Company's hedging strategy are resolved. His recommendations date back to Phase I of this Docket. The Division has made its position known regarding such items in previous testimony and will not repeat them here.

Q. What points does Mr. Brubaker make that are in substantial agreement with the Division's position?

A. If an ECAM is adopted he appears to agree with the advisability of having general rate cases at least every three years; and that the ECAM should be a pilot program. He also seems to generally support the Division's position regarding the treatment of RECs, and wholesale wheeling revenues.

Q. What areas does Mr. Brubaker disagree with the Division?

A. Similar to other intervenors' witnesses, Mr. Brubaker disagrees with the Division's proposal to adjust the sharing percentages if the Company meets certain criteria regarding its hedging program and front office transactions. I have responded to these criticisms above.

Q. Does Mr. Brubaker make valid points regarding differences between customer classes and seasonal load effects?

A. Mr. Brubaker's comments regarding customer classes and seasonal load effects reflect concerns that have been raised in the cost of service phases of general rate cases. Some of these concerns are currently being studied in work groups ordered by the Commission following the most recent general rate case (see Docket No. 09-035-23). At the end of an ECAM period the Company would propose to recover the ECAM and propose rates for the various customer classes based upon the most recent completed general rate case order. At that time parties may propose changes to the proposed rates (or any other aspect of the proposed ECAM recover) for adjudication by the Commission. In this Docket the Division does not argue cost of service issues that should be presented in a general rate case.

Q. Mr. Brubaker calls for the Commission to hire an independent auditor to audit the ECAM. Does the Division have a position on this recommendation?

A. The Division previously has raised its own concerns about its ability to satisfactorily audit the ECAM. Funding for either an independent auditor or for additional Division auditors would likely mitigate the Division's concerns. At this time, though, the Division takes no position regarding Mr. Brubaker's specific recommendation.

III. CONCLUSIONS.

Q. What is your conclusion?

A. The rebuttal testimonies of the Company and intervenors do not persuade the Division to alter its proposed ECAM.

Q. Does this conclude your surrebuttal testimony?

A. Yes.