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Date Submitted: 20 August 2001

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of PACIFICORP for	**)**	**POST HEARING BRIEF**
Approval of it Proposed Electric Rate	**)**	
Schedules and Electric Service Regulations	**)**	**Docket No. 01-035-01**

The United States Executive Agencies (USEA) submits the following Post Hearing Brief in the above captioned case.

INTRODUCTION

The test year used by Pacificorp in this case has certainly been a difficult one for utilities and customers alike across the country. No one can say that the crisis in California has not had some effect on other jurisdictions around the country. Likewise, it is a foregone conclusion that market prices went up nationwide, as did the prices of many types of fuel. Yet, these issues and many others have to be closely scrutinized to determine their exact impact upon the Company and the ratepayers in this case. Even more importantly then just recognizing market difficulties, is how Pacificorp and customers respond to these conditions and what the Commission should do to mitigate future harm – both to Pacificorp as well as the ratepayers.

Pacificorp embarked on a journey into the wholesale market several years ago. Despite assertions by Pacificorp that their wholesale purchases are only to the extent necessary to benefit their rate base customers, it is evident that this is not the case. In fact, Pacificorp made a conscious decision to rely more and more on wholesale transactions (see generally RAMPP-4). Although, Pacificorp is reluctant to admit it, profit must have been a motivating factor in this decision. With a lucrative opportunity in front of them, they took a chance. For a few years this situation seemed to do well for the Company (and surelt the Company and its shareholders benefited from this success). Yet, now that the market has taken a swing in the other direction, Pacificorp is quick to try to insulate the Company and its shareholders from any risk by passing on these losses/costs to the ratepayers.

Pacificorp has proposed significant net power costs in this proceeding to justify their substantial requested rate increase. The Utah jurisdiction net power costs are significantly inflated (as explained in this brief) in comparison to what was presented to both the Oregon and Wyoming Commissions. In particular, Pacificorp has attempted to justify these inflated net power costs by presenting to this Commission: annualized market power prices, lower thermal availability, higher maintenance outages, unreasonable maintenance schedules, and the recharacterization of San Diego contracts historically accepted as short term sales. USEA has already established and will further, in this brief, show that these issues relevant to net power costs have been overstated and therefore should be adjusted accordingly.

Additionally, testimony has been presented in this case regarding a potential rider for demand side management programs. We continue to express our concern over a proposal that has not been subjected to sufficient review, has not been adequately designed and outlined, and has not proven to be necessary to meet the Utah DSM needs.

Ultimately, we ask this Commission to continue its careful scrutinization of Pacificorp's requested rate increase. Upon complete review we believe it is evident that additional adjustments are necessary to ensure equity to both the Company and the ratepayers.

REVENUE CREDIT - $1.3 BILLION DOLLAR BENEFIT

Pacificorp witnesses have repeated touted a $1.3 billion benefit that the Company has passed on to ratepayers. First, this so-called benefit needs to be put into perspective. Second, it needs to be scrutinized for accuracy. The Company's claim is flawed due to the methodology used in this estimate. The Company calculated the difference in revenues between two completely different types of sales: long term and short term. Whereas, the real benefits are the difference between actual costs and revenues from the relevant wholesale transactions.

First, this $1.3 billion has by no means been all passed on to the Utah ratepayers. They only received a share of that amount. See Tr. at 115-117 and 252-253. Yet, even on cross-examination, Pacificorp is reluctant address this issue. Instead, Pacificorp witnesses repeatedly tout this $1.3 billion as if Utah has received it all – that is simply not true.

Even the portion of this benefit allocated to Utah is calculated illogically. This so-called benefit to the retail customers is based upon a comparison of average actual long-term sales prices to potential sales values if the sales had occurred on the short-term market. Tr. at 212-213 and 254-256. Long and short term sales are significantly different both in risk and in price. See Tr. at 263-265. Mr. Watters concedes that comparing long-term firm to short term is not the only means of comparison. Tr. at 292-295. Moreover, Mr. Watters agrees that a decision to sell all of Pacificorp's power on the short-term market would have been imprudent. Tr. at 296. This begs the question: If it would be imprudent to sell all of your power on the short term market, then how can you use only the short term market as your basis for determining the benefit to the customers? This proposal is an apples to oranges comparison. This comparison is not a true cost-benefit analysis where actual cost would be subtracted from actual value to determine a real proceed or benefit. This is a hypothetical benefit based upon a hypothetical comparison.

Ms. Johansen testified that the Company is only looking for a fair and reasonable outcome. Tr. at 19. We would concur with this conclusion. Yet, we feel that Pacificorp has already received more than their fair share. Ms. Johansen also states that Pacificorp has done "a yeoman's job in trying to protect our customers in Utah and other states." Tr. at 19. She further mentions that Pacificorp has adopted "a wholesale marketing strategy that minimizes our risk" and "has benefited, over the last decade, benefited retail customers to a tune of over a billion dollars." Tr. at 20. For all this gratuitous benefit to the ratepayers, Pacificorp asks for a mere $118 million.

Mr. Watters is quick to point out that he feels that the last rate case clearly gives Pacificorp full authority to enter into wholesale contracts without the Commission's approval. Tr. at 144. Yet he is not as quick to acknowledge that the Commission also stated that they must also ensure that any wholesale sales do not harm retail customers. Tr. at 144. In this case the benefit has been grossly exaggerated and the ratepayers are being told they should bear the risk of the Company's wholesale sales decisions.

Pacificorp admits in their RAMPP-4 report their plan for continued reliance on wholesale sales as a major business activity. Tr. at 166. This report came out in 1995 – a time at which Pacificorp was becoming significantly more active in the wholesale market. Tr. at 166. This report spells out Pacificorp's position on wholesale transactions quite well:

> "The wholesale part of our business is growing rapidly and the Company is looking at wholesale sales as a major business activity. Wholesale marketing will increasingly evolve as a separate business with its own strategies, rewards, and risks." RAMPP-4, p. 12; Tr. at 405.

Pacificorp realized then that with these additional sales came additional risk. Tr. at 170. RAMPP-4 is again resolves any confusion on this issue:

> "The greater the Company's activity in the wholesale market, the greater the potential rewards and the greater the risks. Those who bear the risks should benefit from the rewards. The Company would prefer to not expose retail customers to the higher risk/reward situation. … Pacificorp realizes that the future will be more risky than the past." RAMPP-4, p. 13.

Mr. Watters identifies the Company's departure from Pacificorp's goal to insulate retail customers from this increased risk by conceding that, in reality, the ratepayers bear the risk of these transactions. Tr. at 170-171. The Company should not be allowed to talk the talk but refuse to walk the walk. They talk about protecting retail customers but the minute their profits are affected they quickly try to shift the risk to those same customers they allege they are trying to protect. Mr. Watters states that Pacificorp "absolutely" utilizes the RAMPP reports in making decisions. Tr. at 437. That position seems to be only partially true – only to the extent that those decisions are profitable for the Company.

Pacificorp would also like everyone to think that all of their wholesale sales were accomplished solely to benefit the ratepayers. Yet, in reality, the Company is also profiting from these transactions. The shareholders are still receiving dividends every year. The Company is still making a profit. Even in this hearing, Commissioner Campbell has identified, and Mr. Watters agreed, that Pacificorp's wholesale activities clearly provide a benefit to the Company. Tr. at 341-345. These transactions are as much self-serving as they are beneficial to ratepayers, therefore, requiring the ratepayers to bear all or the lion's share of the risk is not equitable.

Pacificorp also attempts to blame the increase in net power costs on the need to acquire replacement power for the Centralia sale. They repeatedly reiterate that the Utah Commission and others approved this sale and therefore, the Company should not have to bear the risk of acquiring replacement power. Tr. at 306. Yet, Mr. Watters concedes that Pacificorp had Centralia was not the source for all of these wholesale contracts. Tr. at 214. In fact, many were entered into before Centralia was sold or even being considered for sale. Tr. at 214. Mr. Watters, though, clearly indicates Pacificorp's position that the ratepayers should bear the risk of additional costs for replacement power for Centralia. Tr. at 307. Ultimately Pacificorp made the decision to sell Centralia – not the Commissions. We assert that Pacificorp's attempts to shift the risk to their customers is simply a means of insulating the Company and their shareholders from the consequences of a business decision ultimately made by Pacificorp alone. The ratepayers did not decide to sell Centralia. Had the sale of Centralia and Pacificorp's wholesale transactions proven to be immensely profitable then we probably would not be having this rate case today. Companies make business decisions everyday. Some choices are profitable; some are not. Just because a business decision does not prove to be as profitable as expected, Pacificorp should not be allowed to use the ratepayers as a safety net to absorb any potential risk. To do so would result in a complete disincentive on utility companies to act prudently and accept responsibility for their actions – especially if they know that they can always shift any loss to the ratepayers.

USEA is not advocating for a prudence review of all of Pacificorp's wholesale transactions. On the contrary, we would concur with Dr. Anderson's explanation that the real issue here is an allocation of risk. Tr. at 1029-1030. The Company ultimately made these decisions and therefore, the Company should ultimately bear the risk of those business decisions. That is the cost of doing business. To act otherwise would unfairly insulate the Company from any business risk associated with any business decision that it may make. Currently, the risk allocation is one sided – the ratepayers bear the risk. Instead, the risk should be more fairly apportioned among all of the affected parties (the Company, its shareholders, and the ratepayers).

NET POWER COSTS

Pacificorp asserts that its net power costs have been $806 million. Yet, in fact, their actual net power costs of $635 million have been approximately $170 million less. Widmer, Tr. at 450. Furthermore, two significant factors impacting Pacificorp's net power costs during this test year, a lower than average water year and the catastrophic failure of the Hunter 1 unit, are not even included in the calculation of Pacificorp's $806 million. See Watters, Tr. at 311-312. The Hunter outage impact has been excluded from this case and the water conditions for the test year have been normalized. So, these factors and the Company's reliance on them are irrelevant to this proceeding. In addition, despite the removal of these significant factors, the Company's net power costs still exceed their actual costs by approximately $170 million. We are not rejecting the use of modeling as a tool in ratemaking. Yet, net power costs should not be artificially inflated to such an extent that they set an unrealistic floor for ratemaking decisions.

It is clear that the net power costs have been inflated by millions of dollar when compared with actual cost and Pacificorp filings in other jurisdictions ($615 million in Oregon and $499 million in Wyoming). Tr. at 451-458. The inflated costs are a result of market price annualization, low availability factors, high maintenance outages, unreasonable maintenance schedules, and limited generation from Gadsby units. Another example of artificial inflation of net power costs is the Cholla outage. Mr. Widmer declares that this outage, despite being significantly longer than any other overhaul he is familiar with, is not an unusual event. Tr. at 487. The Cholla outage lasted 3000 hours in 1996 whereas a typical overhaul is normally four to eight weeks. Tr. at 487 & 1134. One purpose of ratemaking is to as closely as possible approximate the costs of the Company in a manner upon which future rates can be fairly and equitably set. Isolated incidents such as these should not become the foundation upon which years of future rates are based.

THERMAL AVAILABILITY

The Company claims that its thermal availability has only fluctuated within a reasonable range and their forced outage rate is higher than the national average. As a result, they conclude that their thermal availability must also be great. That is a flawed comparison. The Company's statement that its forced outage rate is better than the national average is immaterial in this case. Regardless of the national average, when evidence clearly shows a steady decline in thermal availability, that is an indicator that there is room for improvement. Furthermore, the forced outage rate is only one of the factors used in the calculating thermal availability. Falkenberg, Tr. at 1171. Historical data, when calculated properly and as used in ratemaking, shows the Company's thermal availability on the decline and further establishes that the use of a six-year average will smooth the yearly fluctuations and produce reasonable results.

Several Pacificorp witnesses have conceded that increased efficiency and increased output of Pacificorp thermal units is an important means of offsetting high purchase power costs. Mr. Watters agrees that any means of increasing output where the result would be production of power cheaper than market price would be a wise business decision. Tr. at 273-274. Yet, Mr. Widmer is quick to blame high net power costs on high market prices. Tr. at 443. Although, high power costs should be an incentive for the Company to maximize thermal availability. Mr. Widmer specifically states that thermal performance is not a factor in net power costs therefore a change in Pacificorp's current thermal performance methodology is not warranted. Tr. at 443.

On the contrary, Mr. Widmer agrees that “the purpose of thermal availability is to smooth out the generation levels so that you don’t see fluctuations in your generation levels from year to year, which can have an impact on power costs if your generation level fluctuations are large.” Tr. at 483. We agree with this statement and assert that a six-year average for thermal availability is the better alternative in this case. Pacificorp has failed to establish why their four-year average should be preferred.

Pacificorp asserts that the Company’s thermal availability has only slightly fluctuated within a reasonable range over the last decade. See Widmer, Tr. at 908-909. Mr. Widmer agrees though that Pacificorp’s thermal availability statistics (as presented in his prefiled testimony) only show equivalent availability. Tr. at 912. Yet, for ratemaking purposes, operating equivalent availability data is used. Tr. at 912. Pacificorp’s thermal availability data misrepresents what this Commission should be evaluating. Mr. Herz utilizes Pacificorp operating equivalent availability data that unlike Mr. Widmer’s numbers shows a clear and steady decline in thermal availability. Therefore, for the purposes of this proceeding Pacificorp’s thermal availability data, as presented by Mr. Widmer, should not be considered.

Pacificorp’s proposes to use thermal equivalent operating availability factors in the net power cost model that are based on a 4-year average of 1996-1999. Pacificorp indicates 4-year averages have been used in prior cases and such practices should continue in this proceeding. The USEA and others believe a 6-year average should be used in this proceeding. The following tabulation summarizes Pacificorp’s actual thermal equivalent operating availability factors with that proposed by Pacificorp and compared with prior rate cases and USEA's recommendations:

Year	**Average Thermal Equivalent Operating**	**USEA Recommendation (1994 - 1999)**	**1997 Rate Case (1994 - 1997)**	**1998 Rate Case (1995 - 1998)**	**PacifiCorp Proposed (1996 - 1999)**
1994	94.10%				
1995	93.45%				
1996	92.44%	92.41%	93.01%		
1997	92.04%			92.47%	
1998	91.94%				91.35%
1999	90.52%				

Source - See Exhibit USEA - 1.2 (JAH-3), page 1

Because Pacificorp's factors have been declining, Pacificorp's proposed factors are not consistent with actual historical levels, nor are they consistent with the factors used in the 1997 and 1998 cases. Pacificorp does not offer an explanation as to why its thermal operating equivalent availability factors thermal equivalent operating availability should be used in this proceeding, other than those are the results of continuing to use the 4-year average. USEA recommends the use of a six-year average of 1994-1999, which results in thermal equivalent operating availability factors that are consistent with the purpose of using historical averages (i.e., smoothing out fluctuations), and is consistent with the averages used in the prior two rate cases.

Should the Commission decide to use a four-year historical average, the USEA recommends the Commission: (i) use the six-year period 1994-1996; (ii) eliminate the high year and low year operating equivalent availability factor for each thermal unit in that 6-year period; and, (iii) calculate the 4-year average of the remaining four factors. This alternative approach eliminates the 4-year averages from being influenced by unusually high and/or low factors in the historical period.

Pacificorp also states that a six-year average for thermal availability should not be used because doing so would result in double counting of years overlapping with the previous four-year period. See Widmer, Tr. at 913. Yet, this argument is simply illogical. If Pacificorp believes that USEA shouldn't use a particular period because of concerns over double counting then the last two four year averages used by Pacificorp (in this rate case and the one prior) should not have been used because they each overlap with four-year averages used in previous rate cases. In the 1997 rate case, 1994-1997 data was used. See Widmer, Tr. at 914. In the 1998 case, 1995-1998 data was offered. Id. Finally, in this case 1996-1999 data is utilized. Id. The four-year averages presented by Pacificorp both in this case and in the 1998 rate case each "double count" three years of statistics. What is good for the goose must be good for the gander.

THERMAL MAINTENANCE

Even Ms. Johansen agrees that constantly looking for new ways to improve efficiency in the output of their thermal units is an important means of helping defray higher purchase power costs. Tr. at 91. She also agrees that there is always room for improvement. Tr. at 92. Mr. Watters likewise concurs that upgrades, improved maintenance, and more efficient equipment operation are an important consideration in determining how to minimize the need to buy high cost power off the market. Tr. at 274. Yet, the Company still chooses inefficient maintenance schedules and tries to hide behind forced outage rates and national averages.

As with thermal availability, a six-year average for maintenance is more reasonable because it matches the units' maintenance cycles. This is true for all units except Gadsby – which will be addressed separately. This is a very similar issue to the availability factors in that historical data shows the Company's maintenance hours are increasing in the recent years and the use of six-year average will smooth the yearly fluctuations and produce reasonable results. Pacificorp proposes to input maintenance outages in the net power cost model that are based on the 4-year average of 1996-1999. Pacificorp indicates 4-year averages have been used in prior cases and such practice should continue in this proceeding. The USEA and others believe a 6-year average should be used in this proceeding. The following tabulation summarizes Pacificorp's actual thermal unit maintenance hours with Pacificorp's proposal, and a comparison with USEA's recommendations and prior rate cases:

Year	**Thermal Maintenance Outage Hours**	**USEA Recommendation (1994 - 1999)**	**1997 Rate Case (1994 - 1997)**	**1998 Rate Case (1995 - 1998)**	**PacifiCorp Proposed (1996 - 1999)**
1990	9,380				
1991	12,094				
1992	12,085				
1993	7,483				
1994	12,422				
1995	10,354				
1996	10,987	14,584	13,501		
1997	20,242			15,433	
1998	20,148				16,181
1999	13,351				

Source - See USEA response to the Commission's Data Request, question number 2.
Note - 1990 information does not include outage hours for Cholla, Craig, Hayden and Gadsby Un

Because of the large number of maintenance outage hours in 1997 and 1998, Pacificorp's proposed maintenance outage hours do not smooth out historical fluctuations, are not consistent with actual historical levels, and are not consistent with the factors used in the 1997 and 1998 cases. USEA recommends the use of a six-year average of 1994-1999. USEA's recommendation results in maintenance outage hours that are consistent with the purpose of using historical averages (i.e., smoothing out fluctuations), and that is consistent with the averages used in the prior two rate cases.

Pacificorp proposes to use maintenance outage time for the Gadsby units based on actual historical averages. The Gadsby units were used sparingly during the 1994-1999 period and had a low number of maintenance outage hours during that period. In recognition of the higher modeled use of the Gadsby units in the test year net power cost model, the USEA recommends the maintenance outage hours of the Gadsby units be increased to system average maintenance outage hours, weighted on a MW capacity basis. Herz, Tr. at 1059. The USEA's recommendation is consistent with USEA's recommended approach to Gadsby equivalent operating availability factors.

TIMING OF MAINTENANCE

Mr. Herz has proposed a very reasonable adjustment to Pacificorp's maintenance schedule. Pacificorp has failed to offer any legitimate reason not to accept Mr. Herz's proposal. Pacificorp talks of wanting to maximize thermal performance and improve whenever possible, but conversely strongly opposes suggested improvements in there thermal maintenance operations. Pacificorp proposes to have eight units scheduled for maintenance outages in month of June in the test year net power cost model. This is inconsistent with Pacificorp's past practices and planning of maintenance outages during periods of lower demands and lower replacement power prices. The USEA recommends moving 4 of the 8 units to the off-peak months of February and April.

Pacificorp agrees that such a change in their maintenance schedule would be advantageous to the Company in that it would take advantage of less expensive replacement power available earlier in the year. See Widmer, Tr. at 915-916. Yet, Mr. Widmer claims that USEA's proposed changes in maintenance timing are not feasible because of workforce issues, contractual issues, and weather issues. Tr. at 916. Pacificorp alleges that there are a limited number of contract employees available for major overhauls; therefore moving maintenance from June is not possible. Widmer, Tr. at 916-918. Yet, if there really is such a shortage in the workforce, then why wouldn't the Company spread out their maintenance over a longer period of time. Furthermore, if Pacificorp really is concerned over the availability of this contract workforce, why don't they hire these folks full-time? Finally, if scheduling these contract workers for Pacificorp maintenance truly is a concern then shouldn't Pacificorp be coordinating their maintenance needs with all of the other utility companies who will need these workers? Mr. Widmer concedes that no such coordination occurs. Tr. at 919. These questions show the absurdity of this position. Pacificorp has failed to give any support for their hollow assertion that workforce concerns have, in reality, any bearing on maintenance scheduling.

The Company also expresses that contract issues prevent spreading maintenance out as suggested by Mr. Herz. When asked what specific contract issues are problematic, Mr. Widmer could only come up with one. Pacificorp apparently has an exchange agreement with APS that may hinder their ability to schedule maintenance for Cholla during the summer months. Widmer, Tr. at 919. Apparently, there are no other contract issues that affect maintenance schedules. This Cholla issue also has no effect since: first, USEA is not proposing a maintenance schedule change for Cholla and second, USEA is proposing to move maintenance out of summer months and not into summer months. Again, Pacificorp's assertions have proven to be without merit.

Lastly, the Company alleges that weather issues will prevent moving maintenance to February and April as suggested by Mr. Herz. Specifically, Mr. Widmer asserts that Pacificorp "doesn't like to do very much maintenance in Wyoming during the winter because the weather conditions are so extreme that it makes it difficult to do a lot of maintenance." Tr. at 920. Surprisingly though, Pacificorp had several of its Wyoming plants scheduled for winter maintenance. See Tr. at 920-921. Naughton, Dave Johnson II, and Jim Bridger IV are all Wyoming plants scheduled for winter maintenance. Thus, the Company's own actions directly contradict their reasoning for rejecting Mr. Herz's proposal. Finally, Mr. Widmer concedes that weather is not an impediment in moving maintenance from June to April. Tr. at 921-922.

Pacificorp could not give one valid reason as to why so much maintenance needed to be scheduled in June – one of the highest months for replacement power. Even Pacificorp's Spring

1997 maintenance schedule shows that the Company has not historically overloaded their maintenance in June. See Cross Exam Ex. 21. The Company has been unable to present one viable reason why Mr. Herz's maintenance schedule changes should not be adopted. USEA is not requesting a complete overhaul of Pacificorp's maintenance schedule. A complete review of their maintenance schedule would likely result in further adjustments significantly greater than what is currently proposed by USEA. Herz, Tr. at 1070-1071. Instead, we have identified an anomaly in the Company's proposed schedule (with respect to June maintenance) that just does not make sense and therefore should be altered.

GADSBY AVAILABILITY

There was significant testimony by Pacificorp in response to proposals by Mr. Herz and Mr. Falkenberg to alter the availability of Gadsby as utilized in the model. Mr. Widmer in his rebuttal testimony indicates that the historical availability of the Gadsby units should not be altered because there is not a market for Gadsby power beyond that already being utilized. Tr. at 443. If that were true, though, then why is Pacificorp proposing at 100 MW expansion of the Gadsby units? In addition, that exhibit shows that Pacificorp hopes to have that expansion online by the second quarter of this year. That further questions Mr. Widmer's testimony that there is no market for additional Gadsby power.

The Gadsby units were used sparingly during the 1994-1999 period and had high thermal equivalent operating availability factors (i.e., greater than 97%) during that period. Pacificorp does not use the Gadsby historical averages in its net power cost model. Rather, Pacificorp proposes to use much lower factors so as to reduce the output of the Gadsby units in the test year model to an amount that Pacificorp believes is representative of an on-peak period when secondary prices are high. Pacificorp's net power cost model is a monthly average energy model that does not distinguish between on-peak and off-peak periods, or price differentials between on-peak and off-peak periods.

Pacificorp's proposed handling of the Gadsby units attempts to restrict the use to on-peak period in a model that does not give recognition to the higher on-peak value of the secondary market prices. The USEA recommends that the model be left to run as designed without inserting artificial inputs to force a desired result (i.e., avoid the "garbage in, garbage out" syndrome). The USEA recommends setting the Gadsby units thermal equivalent operating availability factors at the system average (i.e., 92.41%). This is lower than actual historical averages, but gives recognition to the historical limited use of these units.

SAN DIEGO SALES

Pacificorp has historically characterized the four San Diego contracts as short term. Now, less than six months before the last of the four contracts is to expire, they want to change four years of precedent and re-characterize these agreements as long term. Surprisingly, this "mistake" (as Pacificorp refers to it) was only noticed after intervener testimony was filed in response to the Company's rate case filing. Tr. at 501. Only then did Pacificorp raise this issue in an untimely amended filing. Mr. Watters explained how any long-term wholesale contracts (those with a term of longer than one year) are required to be filed with FERC. Tr. at 267-268. Yet, he conceded that the San Diego contracts (which Pacificorp has tried to collectively refer to as one long term contract) were never filed with FERC. Tr. at 268. He attempted to qualify his concession by stating that Pacificorp has recently filed the last San Diego contract with FERC (Tr. at 268) but he later again conceded that no such filing has occurred. Tr. at 383-384. It is interesting to note, though, that Pacificorp could have filed with FERC at anytime (obviously they have known about this "mistake" for quite some time now) but only upon cross examination on this issue does the Company concede that they have not filed with FERC. Of course, they try to qualify that statement by saying they *will* file (on contracts that the fourth one will expire at the end of this year) and only after being forced to answer on the record.

In addition, Mr. Widmer agrees that these contracts consist of four separate one-year agreements. Tr. at 500. On their face, the San Diego contracts are four separately signed contracts – each with its own terms inclusive to itself. Tr. at 501. None of the contracts reference any of the others; they each stand on their own. Tr. at 501. Even in the last rate case, Pacificorp treated these contracts as short term. Tr. at 501. Even when Pacificorp realized their "mistake" in their characterization of these contracts back in late 2000, they did not make any attempt to change the status of these contracts. Tr. at 501. We have already established that Pacificorp did not and has not filed these contracts with FERC – despite having well over half a year to do so. Furthermore, despite Pacificorp's alleged realization of this "mistake" in late 2000, they still filed rate cases in Oregon and Utah that included these contracts as short term. Tr. at 501-502. In Pacificorp's

1999 FERC Form 1, these contracts were not listed at long term. Tr. at 502. Again, although not yet filed, apparently Pacificorp has not corrected their 2000 FERC Form 1 either. Tr. at 502. Substantial testimony has been given regarding Pacificorp's RAMPP reports. These reports list all of the Company's long-term contracts. Nowhere in any of the Company's RAMPP reports are any of the San Diego contracts (the four successive one year agreements) listed as long term. Tr. at 503-505. Mr. Widmer concedes all of these points. Tr. at 500-505. Nevertheless, Pacificorp still asserts that these agreements should be reclassified as long term thereby increasing their revenue requirement. Despite being aware of this "mistake" since late 2000, Pacificorp did not make any attempt to correct their "mistake" until testimony was presented in this case that identified errors and adjustments resulting in a decrease in their revenue requirement. Only then does the correction of this "mistake" become a necessity – to the tune of a $17 million increase in their revenue requirement.

DSM RIDER

Although Mr. Burks amended his prefiled testimony on the record to delete the reference to including the $35 million DSM rider in the revenue requirement of this case, we want our concerns to be noted on the record in case this matter is further discussed or even addressed at a later time. Tr. at 517 & 539-540. USEA are not by any means opposed to DSM. Kent Nomura, Hill AFB's Energy Manager, during Public Witness Day, testified that Hill AFB alone has spent approximately $68 million on energy conservation with hopes of spending at least that much more over the next few years. Tr. At 807-808. USEA are concerned that our proactive approach to conservation may put us at a disadvantage should a DSM rider be put into place.

Hill AFB has an active and diversified energy conservation program. Mr. Nomura explained that Hill utilizes several mechanisms to achieve their energy conservation goals. Tr. At 807. DSM is only one of the means that Hill uses to meet its conservation needs – also included are energy savings performance contracts (ESPC) and the federal energy conservation investment program (ECIP). Hill AFB has partnered with Pacificorp in substantial DSM efforts and as a result has saved a significant amount of energy. Yet, Hill AFB has also awarded ESPC and ECIP contracts. Despite Mr. Nichols assertion that performance contracting companies in Utah don't have much business in the industrial market, we would like to reiterate that Hill AFB does have an active energy performance contract and has spent 10's of millions of dollars under that agreement. Tr. at 583.

Our concern centers on being forced to pay into a program that may be of marginal, if any benefit, to Hill AFB and therefore not being able to do as much conservation through other mechanisms. Hill AFB has a current DSM contract with Pacificorp to do energy conservation. Yet, the rider, as proposed, would require an additional surcharge above anything Hill decides to do on its own with Pacificorp or through other means. We understand the importance of DSM for all customers but we also feel we are setting an example for other customers – yet would be penalized by this rider for being proactive.

USEA are continually searching for additional conservation opportunities. We even have federal mandates to conserve energy. Yet, we cannot and should not put all of our eggs in one basket. Furthermore, the proposed DSM rider and Tellus study are not clear on specifically what programs would be implemented, how they would benefit each customer class, and who should pay what. To award $35 million without knowing how it will be spent would not be a wise allocation of funds. More details need to be presented to determine the exact effect this proposed rider would have on the customer classes.

Additionally, we are concerned about not receiving any credit for past or future conservation not done under DSM. Hill AFB has already, through its current energy conservation efforts, saved 611 million kilowatt hours per year. Tr. at 808. Should Hill AFB have to pay such a rider, but then do its conservation through ESPC, for example, Hill would not receive any benefit from its payment into this DSM program. We would like to see some offset mechanism or other means of preventing proactive customers from being penalized by doing energy conservation via other means than DSM. Dr. Nichols concedes that this DSM rider would result in some customers paying into a program from which they cannot receive any benefit. Tr. at 527. This is the exact situation we feel USEA will be faced with should this rider be approved. Hill AFB has already done so many energy conservation projects that many things, for example energy efficient interior lighting, are not an issue for the base because all of the necessary upgrades have been completed. As such, should Hill have to pay into a program to provide energy efficient lighting, for example, the base could not receive any benefit – thus being penalized for being proactive.

Moreover, Pacificorp has proposed DSM programs that should be evaluated on their merits before an outside program is forced upon the company and its customers. Hill AFB has had a fruitful and mutually beneficial relationship with Pacificorp with respect to DSM and we believe this rider may negatively impact our situation. Not to mention with the volatility in the energy market and the likelihood that prices may go down, is now the time to really commit such massive resources ($195 million over 6 years – see Nichols, Tr. at 531) based upon a study that has not received an outside critical analysis or comprehensive review?

Dr. Nichols claims that Pacificorp will not do anything regarding DSM without a push from the Commission. Tr. at 532. That simply is not true. Pacificorp has offered DSM proposals for review. See Nichols, Tr. at 551. Even more importantly, Dr. Nichols has admitted that Pacificorp has invested up to $22 million in DSM with Hill AFB alone. Tr. at 576. Hill AFB admits that it has received benefits from DSM, but the base has also paid substantial sums into DSM and other conservation programs. Ultimately, these are not indicators that Pacificorp needs to be forced to adopt the proposed rider and programs. For these reasons we oppose the DSM rider as presented in this case. Hill AFB has a long standing relationship with Pacificorp regarding DSM services and we hope that this Commission would not order Pacificorp to embark on a course that in contrary to their and our best interests.

We feel that this Commission should support DSM and encourage the Company to propose and implement worthwhile programs. Yet, we agree with Mr. Sterzinger that further review of DSM proposals including the offered rider is necessary to ensure that these programs "live up to expectations." Tr. At 611.

CONCLUSION

Pacificorp would have this Commission believe that absent a substantial rate increase, the future of their company is in grave danger. Yet, as Mr. Gorman pointed out, Pacificorp, through Ms. Clark, once before took the position that if this Commission did give them their full requested increase the result would be negative impact on their bond rating. Tr. At 712. At the interim hearing this Commission gave the Company less than half of what they requested and the credit rating agencies still found such action to be "supportive of the Company's financial condition." Tr. At 712.

Pacificorp has also presented there case for a significant rate increase to the Oregon and Wyoming Commissions who, to date, have only responded with increases of $23 million and $9 million, respectively. Johansen, Tr. at 30. Yet, this Commission has already given Pacificorp an interim increase of $70 million. Ultimately, due to all of the aforementioned reasons, Pacificorp has failed to show the necessity for the significant increase requested.

Respectfully submitted this 20th day of August 2001.

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application	**)**	**Docket No. 01-035-01**
Of Pacificorp for an Increase in	**)**	
Its Rates and Charges	**)**	**CERTIFICATE OF SERVICE**
	)	

I HEREBY CERTIFY that true and correct copies of the U.S. Executive Agencies' POST HEARING BRIEF were mailed to each of the following this 20th day of August 2001:

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