BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN ORDER APPROVING AVOIDED COST RATES	))))))	Docket No. 03-035-14 REBUTTAL TESTIMONY OF RICHARD COLLINS

MAY 6, 2004

Q. Will you please state your name, address and business association?

A. My name is Richard Collins; I am an Associate Professor of Economics and Finance at Westminster College located at 1840 South 1300 East, Salt Lake City, UT 84108.

QUALIFICATIONS

Q. Who are you representing in this Docket?

A. I am representing the UAE Intervention Group and its respective members.

Q. Have you formally testified before this Commission before?

A. No, I have not.

Q. What experience do you bring to this proceeding?

A. Prior to my position at Westminster College, I worked for the Public Service Commission of Utah for approximately 13 years.

Q. What were your responsibilities while at the Commission?

A. I provided technical advice to the Commission on rate proceedings and a variety of other issues. I was responsible for tracking PacifiCorp's IRP planning process, avoided cost, demand-side management, cost of capital, and deregulation issues. In addition, I helped write orders and wrote or coauthored a series of technical reports on deregulation issues for the Commission and the legislature.

SUMMARY OF TESTIMONY

Q. Could you please summarize your testimony in this proceeding?

A. First, I provide background into PURPA and avoided costs and point out some of the pitfalls that can be encountered in determining their value. Next, I present a critique of the proposed methods for calculating avoided costs presented by the parties in their direct testimony. If the Commission adopts a given party's method, I recommend changes, which will improve its performance as a predictor of avoided costs. Finally, I suggest an adaptation of the proposed methods; I select the best qualities of the methods and request that the Commission consider a blend of methods that draws from the strengths of each.

Q. Could you give a summary of your conclusions and recommendations?

A. Yes,

- I have concluded that all methods presented by the parties' in their direct testimony have significant flaws.
- I recommend that the Commission choose amongst the methods the specific components that best estimate the full avoided costs of a QF. This will ensure ratepayer indifference and secure for society the benefits associated with QF generation.
- If the Commission decides to adopt a given party's method, corrections should be made to eliminate distortions, as recommended in my testimony.
- I recommend that the Commission reject the differential revenue requirement method for determining avoided energy costs. The reason is that this method is not practical, cannot be verified, sends unclear price signals and serves as a barrier for QF development.
- The Commission should base the energy costs on actual fuel prices. A variant of Desert Power and U.S. Magnesium's recommended approach is appropriate and should be adopted.

- Short run capacity costs should be based on the capital costs of a SCCT and paid all twelve months of the year.
- Long run capacity costs should be based on the costs of a CCCT.
- If the Commission orders a study group to refine the methodology, it should instruct the group to develop two alternative methods, a differential revenue requirement method and an "ideal" proxy method. The Commission can then select amongst the two. A time limit of six months should be placed on the study group.

COMMENTS ON POLICY CONTEXT

Q. Can you give some background into PURPA and the State of Utah's law on cogeneration and renewable resources?

A. These laws were passed in order to encourage more efficient use of energy and to encourage environmentally benign power production. It is interesting to note that PURPA was passed during an era of growing dependence on foreign oil and rising energy costs, very similar to today's environment. The laws require that regulated public utilities purchase power from Qualifying Facilities (QF) at their full avoided costs. These QFs either produce both heat and power and thereby increase the efficient utilization of energy or use renewable energy, which provides beneficial environmental externalities; an economist's way of saying they do not pollute the environment. PURPA was passed in part to promote greater energy independence for the country.

Q. Isn't forcing the utility to purchase power harmful to the ratepayers?

A. No, avoided costs should be set so that ratepayers are indifferent, that is, the utility pays only the costs that it could avoid because of the purchase of power from the QF. Rates should stay exactly the same.

Q. Shouldn't regulators err on the side of caution and set rates at below full avoided costs?

A. No, they should not. It has been my experience that regulators routinely underestimate avoided costs in order to "protect" ratepayers. The fear is that by setting QF rates too high ratepayers will be harmed by higher rates. But purposely setting rates on the low side will actually harm ratepayers and society because it discourages QF development and denies society the benefits of more efficient utilization of energy and the associated environmental benefits. Such a bias is not good public policy. Regulatory efforts should peg avoided costs rates at the best unbiased estimate of their actual value. In addition, QFs are competitors of the utility thus it is natural for the utility to place roadblocks in the QFs way. When given the chance to compete, QFs will force the utility to seek cost efficiencies thus benefiting ratepayers.

DISCUSSION OF AVOIDED COST CALCULATION METHODS

Q. There appear to be two general methods for calculating avoided costs. Can you briefly summarize them?

A. The two general methods proposed are either a differential revenue requirement approach or a proxy approach, although some parties in this proceeding have proposed a combination of the two.

Q. What are the general strengths and weaknesses of the differential revenue requirement approach?

A. The differential revenue requirement approach has strong theoretical appeal. The utility's revenue requirement is calculated by a production cost model. Two separate runs are made, one without the QF and another with the QF assuming it has no cost. The difference between the model runs is the avoided energy cost. If the model is a capacity expansion production cost model then the difference will theoretically yield both capacity and energy costs. Testimony in this case indicates that there are a variety of approaches that can be used with this method. Both the Committee and the Division favor this general approach. In particular, the Division advocates the use of the "Ideal" approach, developed by the Tellus Institute. These methods can provide accurate avoided cost estimates only to the extent that planning assumptions used in the model are accurate.

Q. Given the theoretical strength of this method, why don't you advocate its use?

A. There are a number of practical problems with the differential revenue requirement method. First, it requires projections on critical inputs used in the model. If the inputs are incorrect, then the model will produce inaccurate results. One critical input into the model, projected fuel prices, has been notoriously inaccurate. I should remind the Commission that it was projections about future energy prices, explicitly the future price of oil, which got California in trouble when it approved the QF Standard Offer # 4 payment stream in the early 1980's.

Q. What are other weaknesses of this approach?

A. A second problem, and perhaps the most serious, is the inability for parties to independently verify and reproduce results. Models that employ the differential revenue requirement approach are highly sophisticated and are not easily accessible to the QFs and their analysts. The model is controlled by the Company with model runs performed by the Company at the request of the parties. This "black box" quality makes it virtually impossible for outside parties to replicate and verify the results. Without independent verification, public confidence in the results is lacking. Inadvertent errors in inputs or logic of the model will produce inaccurate results. Given that the Company generally is the operator of the model there is an asymmetric incentive to validate the model's results. If the model produces avoided cost numbers that are too high, the Company has an incentive to double and triple check the inputs and find the errors. If the results are too low there is less of an incentive to recheck the results. Even if the Division and Committee have access to the model, it will require a tremendous amount of labor to understand and learn how to run it. Given their limited resources and their substantial case load, it is uncertain whether the results can be adequately scrutinized. Even if the model were made accessible to all parties, it places the QF developer at a competitive disadvantage. To analyze and run these models is an expensive proposition. When the Company incurs these expenses they receive cost recovery, however, such costs are not recoverable by QF developers.

Q. Any other problems?

A. Yes, the model is generally based on the IRP planning process, which happens every two years. In the interim between IRP reports data and critical inputs change. There is a tendency for the Company and regulators to want to update inputs and model improvements in order to get a more accurate estimate. This is an admirable goal. However, it leads to inadvertent but unavoidable delays for producing avoided costs. Any updates will require independent verification by parties, a time consuming and expensive proposition. Developers have a limited time frame in which to get financing and develop their projects. This causes a delay in the update of avoided costs, which in turn stymies QF development.

Q. What is your recommendation regarding the differential revenue requirement approach?

A. Recommend that the Commission reject this approach as a viable method for determining avoided costs. Although theoretically pleasing, it simply is not practical. Its use will create a barrier, which will forestall and possibly prevent QFs from developing projects in Utah. If the Commission is convinced that this method should be adopted, then I recommend that the Commission guarantee access to the model for all parties. To relieve this financial burden the Commission could order the hiring of a consultant who will be able to train parties on how to use the model.

Q. What is your opinion of the proxy method for determining avoided costs?

A. From a theoretical perspective, the proxy method is less attractive. Using a proxy plant assumes that the QFs operating characteristics are similar to the proxy plant.

Q. Is this a critical problem?

A. It is a problem, but not critical; if crafted correctly this problem can be overcome or it can be dealt with through a variety of adjustments.

Q. What is the strength of the proxy method?

A. The major strength of this method is that it deals with known information. Costs on proxy plants can be verified by actual data on the proxy plant. I am more comfortable with known and measurable costs than with projections of costs that are nearly impossible to verify and will be wrong. One of the things that regulators should attempt to do is minimize their errors. It is better to be a little inaccurate than very inaccurate. The proxy method will give good approximate results and will minimize the chance of being very wrong.

Q. Are there other advantages of the proxy method?

A. Yes, besides the method being simple and verifiable, this method produces stable estimates of avoided costs. Unless there is substantial technological change that either increases or decreases costs, the avoided costs will stay fairly constant. Stable avoided cost estimates will benefit ratepayers. A strong alternative source of generation will force the regulated utility to lower its costs if it expects to continue building new generation plants. Lower utility costs mean lower rates. Stable QF rates will send clear price signals to potential developers, with known potential revenues developers can get creative to lower costs on their projects. In addition, a stable QF rate also avoids unreasonable delays and minimizes the substantial at risk regulatory expenses that QF developers have to incur. Unlike the Company, QF developers do not receive reimbursement of these expenses.

REBUTTAL OF COMPANY'S CALCULATION METHOD

Q. Let's now turn to your analysis of the parties' recommended methods for calculating avoided costs. The Company recommends a method that

combines both the differential revenue requirement approach and the proxy approach. Do you care to comment?

A. Yes, the Company's proposal uses both methods. In the short run, when the Company claims it has sufficient capacity for about half the year, it uses the differential revenue requirement approach for estimating energy costs and a proxy model for short run capacity costs. The GRID model is the production cost used for energy costs, while capacity is based on a three month payment based on the cost of a Simple Cycle Combustion Turbine ("SCCT"). In the longer run, when the Company is insufficient in capacity and energy throughout the year, it proposes using a Combined Cycle Combustion Turbine ("CCCT") as a proxy for determining both capacity and energy costs. After determining the avoided cost via this approach, the Company proposes a series of adjustments to the pricing of individual QF projects to make them more comparable to the proxy's operating characteristics and costs.

Q. Do you have concerns with this method?

A. Yes, I see a number of problems with this approach. Let me first list them and then describe them in greater detail. The first problem concerns the use of the GRID Model to calculate short run avoided energy costs. The second problem centers on the calculation of short run capacity costs. There are two separate issues to this concern. The third problem is the selection of the proxy for the long run capacity and energy costs. The fourth concerns the capitalization of energy costs. The fifth is the use of projected gas prices to determine a long-run energy rate. These problems call into question the justification of this approach. If the Commission decides to accept this approach then these flaws should corrected.

Q. Can you elaborate on your concern about the use of the GRID model for calculating short-run energy costs?

A. My first concern is the black box nature of the model. I personally am not acquainted with the model but I believe this is a production cost model that has recently been adopted by the Company for ratemaking purposes. I would hope that the Commission staff has had an opportunity to dissect this model and confirm its internal logic. Secondly, the model uses projected fuel costs to determine avoided energy costs. This will lead to inaccuracies that harm either ratepayers or developers.

Q. What is the problem with the Company's calculation of short term capacity costs?

A. This is an area the causes me grave concern. The Company's direct testimony states that it is short capacity in the three summer months in the years 2004 thru midway 2007. However, the Committee's testimony shows that the Company is short 5 to 6 months for each year of this period. If the Committee is correct, then QFs should at a minimum be paid capacity costs for months that the Company is actually short.

Q. You mention that you have another concern with the calculation of short run capacity costs.

A. Yes; I have a problem with how the Company calculates its avoided capacity costs during the months that they are short. It calculates capacity payments based on the cost of a SCCT. By the Company's logic, it is short three months or one quarter of the year, therefore, it bases capacity payments on one quarter of the capacity costs of a SCCT.

Q. Isn't that fair, only paying for one quarter of capacity costs if you need capacity for three months of the year?

A. No. PURPA requires payment based on the costs the utility could avoid by purchasing from the QF. If the Company is short in three summer months, it will either have to purchase peaking energy at market prices or purchase a SCCT so it can run as needed.

Q. Has the Company executed either strategy and if so what were the rate implications?

A. Yes, the Company has both purchased power on the open market and built SCCTs to meet its peak needs. I believe that the Company seeks to recover its market purchases at their actual costs and seeks to place the full costs of their SCCTs in rate base thereby recovering a full twelve months of capacity payments, not just the months in which they operate.

Q. But wouldn't paying one quarter of the price of a SCCT be a good estimate of the cost of purchasing power on the open market?

A. No. Market prices are determined by both supply and demand. In the summer time demand for peak power is at a maximum. To use only the cost side of the equation would severely underestimate its true value and thus underestimate its avoided costs. Every economist knows that market prices are set by both supply and demand.

Q. Can you give an everyday example to help me understand your argument?

A. I will try. Let's assume that you have a large family and take summer vacations that require the use of a Motor Home. You could either buy the Motor Home from a dealer and make the monthly payments or rent the Motor Home from a rental agency for the three summer months. The family should choose the least expensive option.

Q. How would the rental agency set its monthly rental charge? Wouldn't they determine their monthly costs as well at their administrative and capital costs and charge that for the months in which they rent their vehicles?

A. No. The demand for Motor Homes varies over the year. In the winter they might not rent the vehicle but in the summer the demand will be at maximum. They will try to recover as much of their fixed costs as possible in these months. They will charge what the market will bear; they take into account both supply and demand conditions.

Q. What about the purchase option?

A. I doubt the family could convince a Motor Home Salesman to sell them a vehicle and then have him accept payments based on the number of months the family used the vehicle.

Q. What is your recommendation for short-run capacity costs?

A. If the Commission adopts the Company's proposal, then short term capacity rates should be made based on the cost of a SCCT but paid for 12 months just like the utility would get paid.

Q. Your third area of concern about the Company's proposal centered on the use of the CCCT as a proxy for determining the long run capacity and energy payments, can you explain your concern?

A. I am somewhat uncomfortable with the use of a single proxy over the long run. Company contracts with QFs can be structured on ten, twenty or thirty-year duration. During that period of time the Company will be building not just CCCTs, but, according to its last IRP, a whole portfolio of generating resources. These include coal, wind, and CCCTs. The purchase from a QF will avoid or delay some or all of these generating resources. In order to better approximate these costs, I suggest the use of a weighted average of the capital and energy costs be used to calculate avoided costs. However, the construction of such a weighted average will require further study, a job for a future task force. In the interim, I recommend the temporary use of a CCCT.

Q. Is this concept of a weighted average used in other aspects of the Company's business?

A. When the Company is evaluating a capital investment it normally uses a capital budgeting analysis. The Company will determine the investment's internal rate of return, (IRR) and compare it to its cost of capital. The relevant cost of capital is the weighted average cost of capital (WACC), which takes into account the amount of debt and equity that are in the capital structure and their respective costs. Even if the investment is to be financed with lower cost debt, the WACC is the metric used for determining whether the investment is profitable. Using a weighted average cost of the generating resource contained in the Company's optimal portfolio is a good metric to evaluate the payments for a QF.

Q. Your final concern about the Company's method of calculating avoided cost concerns the capitalization of energy costs, could you explain?

A. The Company has proposed to pay avoided capacity costs based on the costs of a SCCT even though the proxy, a CCCT, has higher capital costs and thus would entail a higher capacity payment.

Q. Isn't this method unfair if it pays less than full value?

A. Yes, it is unfair, but not for the reason that you suggest. The Company proposal attempts to make up for the difference by paying an energy rate that recognizes the difference between the capital costs of a CCCT and an SCCT. There are two problems with this approach. First, capacity should be paid even if the unit is not dispatched. Capacity is the ability to produce energy, it is necessary to insure the reliability of the system. Secondly, by paying for capacity costs in an energy rate, it has the potential of changing the economic dispatch of the resource. If the contract energy rate is used to place the resource in the dispatch stack, then this change will cause the dispatcher to assume that the resource has a higher energy cost than it really has. Thus it will be dispatched less often than if it's true energy costs were used. This causes inefficient dispatch, a costly proposition for ratepayers. Secondly, it is unfair to the QF owners because the resource might not be used enough to pay for its full capacity costs.

Q. What do you recommend?

A. If the Commission adopts the Company's method, the Commission should order the Company to eliminate the energy capitalization step and base capacity payments on the cost of a CCCT. This will entail higher capacity payments and lower energy payments for the QF, but it better approximates the true avoided costs of the Company.

Q. The Company proposes to make a series of adjustments to the "standard" avoided cost rate depending on the characteristics of the QF. Could you comment on these adjustments?

A. Yes, the adjustments are discussed in Bruce Griswold's testimony and he argues that they should be reflected in the power purchase agreements with large QFs. Griswold starts with the standard avoided costs, which assume that the QF will have optimum operating characteristics and will impose no additional integration costs on the Company's system. "The second step is to identify, pursuant to PURPA, the level of costs the large QF actually allows the Company to avoid."[1] Griswold identifies approximately six adjustments plus another series for wind resources that should be accounted for.

Q. Could you discuss these adjustments?

A. Yes, the first adjustment concerns the type of power delivered to the Company, if the QF provides firm power then they have a right to both an energy payment and a capacity payment. If the power is non-firm than only an energy payment is due. Furthermore during the sufficiency period non-firm power should have its price discounted by 7% to reflect the cost of reserve capacity embedded in market rate.

[1] Bruce Griswold's February 3, 2004 Testimony in Docket No. 03-035-14 p.2

Under UAE's proposal this adjustment would hold only for the low load hours in which the Palo Verde index is used.

Q. What about the adjustment for availability?

A. The Company states that a QF should be able to meet its daily as well as seasonal peaks. If it cannot meet the peak during the month then it would not receive capacity payments that month. This penalty is too harsh. Taken literally, if a QF fails to meet one daily peak during the month it would not receive any capacity payments that month. Capacity payments should be adjusted for failure to meet peak demands but not eliminated entirely. Such a policy could come back to haunt the Company. For example, if a QF missed a peak period at the beginning of the month, it would have no financial incentive to provide peak power during the rest of the month. Also note the company does not incur this stringent penalty itself. A prorated capacity payment is an appropriate remedy so long as the utility's facilities receive the same treatment. This issue should be addressed in the study group, but until resolution is reached the adjustment should not be enforced.

Q. What about the ability of the Company to dispatch the QF?

A. This relates to the ability of the QF to perform in comparison to the proxy. If the QF's capacity factor is less than the proxy unit than its capacity payment should be reduced, if it is greater than the proxy the capacity payment should be increased. This adjustment is not opposed by UAE

Q. Are there other adjustments?

A. Yes, there is an accounting adjustment that the Company is proposing that adjusts rates to account for any costs that the Company may incur if the value of the QF contract is imputed as debt. I support Mr. Gutting's suggestion that this issue be sent to the task force.

Q. Any other adjustments?

A. Yes, there are a series of adjustment that relate to wind resources that will affect their rates. UAE has not taken a position on any of these adjustments.

Q. Does the Company provide a fair list of adjustments to reflect their intended goal, which was to identify, pursuant to PURPA, the level of costs the large QF actually allows the Company to avoid?

A. No, I do not believe so. The adjustments proposed by the Company all lower the payments made to the QF. If the goal of the adjustments is to identify the level of costs the QF actually allows the Company to avoid then adjustments should be made to account for additional costs that are avoided. These will mitigate the Company's adjustments and possibly lead to higher payments to the QF.

Q. Can you identify some of these positive adjustments?

A. Yes, they include avoided transmission and distribution losses[2] and in some cases a QF's ability to supply valuable ancillary services, such as the ability to meet spinning reserve standards or provide var and/or voltage support to the local distribution system; some QF's will mitigate large unit outage risk. These additional adjustment items should be reviewed in any task force process and considered in individual contract negotiations. Also, it is important to be

[2] The Company has stipulated with FERC that transmission losses are 4.48% in real losses. PacifiCorp's 2003 IRP Appendix C P. 217.

compared to the proxy on a fair basis. For example, PacifiCorp's proxy has its own capacity or heat rate degradation over time, which we have not seen included in the Griswold comparison. Further, the IRP states that CCCT's will be used 74% in Utah[3]. The basis and reasonableness of the 85% proxy capacity factor in the Griswold comparison is questionable. In sum, we advocate a fair, full, unbiased comparison to the proxy.

Q. What are your recommendations for dealing the Griswold adjustments?

A. These adjustments should only be allowed if the other positive adjustments are included. Both sets of adjustments have been inadequately studied, so the Commission should assign this task to the study group.

REBUTTAL OF DIVISION'S CALCULATION METHOD

Q. What does the Division recommend?

A. The Division makes two recommendations; it first recommends that the Commission adopt the Tellus "ideal" method. This is a differential revenue requirement method that has a lot of theoretical appeal but has the same practical problems I discussed earlier. The Division's second choice is a hybrid method which combines differential revenue approach for the early years, a proxy plant method for capacity costs in the later years and an energy cost payment based on known fuel costs.

Q. Could you provide an evaluation of the Division recommendations for adopting a method for calculating avoided costs?

[3] [3] PacifiCorp 2003 IRP Appendix C "Assumptions", P. 215

A. As much as I like the theoretical appeal of the Tellus method, I think that from a real world perspective it is impractical. The model will be difficult to verify, the ideal method requires that each QF proposal be individually modeled into the IRP to determine the differential revenue requirement. This will require a detailed examination of the results of the IRP model run for each QF proposal. This is the perfect recipe for obfuscation and delay by parties opposed to a particular project. Secondly, it presupposes that the inputs into the model approximate reality, a proposition with low probability.

Q. What's your opinion of the hybrid method?

A. I think a method that combines the best of all the proposed methods has real possibilities and I applaud the Division for its attempt. I just don't think they included the best from each proposed method. I support further study if it leads to some consensus on the issue. I fear that because parties have a basic disagreement on which general method to use little or no progress will be made. However, QFs need a reasonable method now during the interim period while parties study the issue.

REBUTTAL OF COMMITTEE'S CALCULATION METHOD

Q. Will you comment on the Committee's proposed method and on it adjustments to the Company's method?

A. Yes The Committee recommends a different general method for calculating avoided capacity and energy costs which we believe is an improvement over the Company's approach in theory, but we feel is lacking in a number of areas. The Committee also recommends a number of adjustments to the Company's method and corrects a number of errors and flaws. UAE agrees with most of these corrections and recommendations and urges the Commission to adopt them. They will be detailed below.

Q. What is the Committee's recommendation for avoided energy costs?

A. The Committee recommends the use of the differential revenue requirement approach to determine avoided energy costs, not just for the period in which PacifiCorp is partially sufficient in capacity, but for the entire planning period. The Committee recommends the "IRP" approach originally proposed by the Company in its May 27, 2003 submission. This approach relies on the Company's projection of natural gas prices, which the Committee rejects as too low. The Committee recommends the use of national gas price indices that are adjusted to reflect pricing in the Western market. As an alternative, the Committee recommends that actual gas prices be used to set avoided energy costs if the Commission is concerned about gas price volatility.

Q. What is UAE's position on the Committee's avoided energy cost recommendation?

A. UAE is in favor of a method of determining avoided energy cost that relies on actual gas prices. This minimizes the potential for over or under payments to QFs and best meets the intent of the ratepayer indifference criterion. UAE does not agree that the differential revenue requirement approach should be used for the entire contract period because the further out you project fuel prices the greater the probability that you will be wrong. If the Commission decides to use gas forecasts to calculate an avoided energy costs we do support the Committee's suggested use of a national price index such as NYMEX or prices out of Henry's Hub with a price differential applied to this index. We do not agree with the Committee's support of a 70 cent negative differential between Henry Hub and Opal pricing. That number is not supported by recent history. The proper number is somewhat lower, about 65 cents. Given the planned additions to western pipelines; this differential should diminish over time.

Q. What is the Committee's position on avoided capacity costs?

A. The Committee supports the use of the proxy method to determine avoided capacity costs but recommends that the capacity costs be determined by the resource that is actually being deferred. In the years where a gas plant is deferred than avoided costs are determined by gas plant's capacity costs, if a coal plant is deferred then coal is used to determine capacity costs.

Q. What is UAE opinion on the Committee's suggestion?

A. This is promising, but we are uncertain about how the costs would be determined or averaged over the contract period. We feel that additional study into this method is warranted.

Q. Will you comment on the Committee's recommended corrections to the Company's methods?

A. Yes, UAE agrees with a number of recommended corrections, which are listed below:

1. Expansion of the number of months that capacity payments are made to QFs in the sufficiency period. The Committee provides evidence that the Company is short capacity for six NOT three months.[4]
2. Correction of the error of variable and fixed O&M costs assumed for a SCCT.
3. Correction of PacifiCorp's variable O&M cost conversion error.
4. If the Commission adopts the differential revenue requirement approach UAE supports the use of Prosym model over Grid model until we can be convinced otherwise.
5. PacifiCorp's adjustment for QF non-availability during peak periods. This adjustment would eliminate capacity payments to QFs unable or unwilling to supply power during peak periods defined as daily and seasonal peaks. The Committee recommends an adjustment if power is not delivered during peak rather than the elimination of capacity payments. UAE supports this recommendation.
6. PacifiCorp's rights to dispatch. This needs further study.
7. Accounting Standards Adjustment. See witness Gutting for UAE's position.

REBUTTAL OF USMAG/DESERT POWER CALCULATION METHOD

Q. Can you review and comment on the testimony of Roger Swenson?

A. Yes. Mr. Swenson testimony provides an improvement on the Company's method and addresses a number of practical problems that has plagued the QF

[4] See page 8 Figure 3 of the Committee's April 9, 2004 Memo to the Commission in Docket No. 03-035-T10.

industry. As detailed by Swenson's testimony, there are Federal and State mandates that encourage QF development for a variety of reasons. Yet the track record in Utah is dismal. QF rates should be set at full avoided costs and should include a capacity payment and energy payment that leaves the ratepayer indifferent, yet yields both economic and environmental benefits for the residents of this state. Thus it is in the public interest to encourage QF development that leaves the ratepayer indifferent. This is the Commission's statutory mandate under both State and Federal law.

Q. Can you describe the Next Deferrable Plant "NDP" method advocated by Mr. Swenson and give a brief evaluation of this approach?

A. The NDP method is based on specific and verifiable costs associated with the building and operation of a specific plant with specific variable costs. This method is a vast improvement over the Company's proposal because it represents a clear, verifiable, reproducible method for calculating avoided costs. This is important because it lessens the ability of any party to manipulate the method to its advantage. It will mitigate delays that can frustrate developers. It also provides a more reasonable estimate of avoided costs because it is based on actual costs not projected costs.

Q. Would this method be used for both avoided capacity and energy costs?

A. Yes, the capacity cost payments would be based on the actual cost of the plant that could be deferred, either the lease payment or the capital recovery schedule, i.e., depreciation schedule. It would also include fixed operation and maintenance costs in the capacity payment. For the energy payment, rates would be based on the heat rate of the NDP and the actual incurred expense for fuel measured by a price index indicative of Opal or a similar western hub. This would protect both the ratepayer and the QF by guaranteeing that actual avoided energy costs are paid. The Company could dispatch the QF in the same manner as the NDP. If the QF provides unscheduled power then payments would mirror non-firm market prices if the Company is a net seller or firm market prices if the Company is a net buyer. This would promote ratepayer neutrality.

Q. What does Swenson suggest for the next deferrable plant?

A. He recommends the West Valley plant because its lease is up for renewal in 2006. The avoided capacity costs would be based on lease payments plus a fixed operations and maintenance costs based on actual historical data. Energy costs are based on West Valley's heat rate times the "actual" delivered fuel price at the time of delivery.

Q. What are the strengths of this method?

A. The primary strength is the fact that the avoided cost rate is based on real numbers, not projections. This should give regulators greater confidence in their accuracy. I believe that it is better to deal with real numbers and be assured of their accuracy then be "theoretically" correct but use uncertain data that impairs its accuracy. This is the reason that the Commission has relied on the historical test year in its rate cases. Secondly, this method is easily understood and can be verified without undue cost or time. This is important. Thirdly, the method can be adjusted as new plants come on line, so it has a degree of flexibility.

Q. What are the weaknesses?

A. The major weakness of this method, in my opinion, is that is relies on only one plant, the next deferrable plant. If the QF does not approximate the running characteristics of the NDP then the QF could potentially be under or over paid. I can anticipate some skepticism on the Commission's part in adopting this method because it is perceived that the West Valley plant is an expensive plant and one that may be expensive to run. It may be more acceptable to use a CCCT as the proxy NDP, particularly for the long run, possibly using the cost of West Valley in the short run.

Q. If the Commission is uneasy about basing avoided costs on the West Valley plant, does it call into question the renewal of this lease?

A. It would appear so. But I do not know the details of that lease agreement.

Q. Do you have any suggestions for overcoming this weakness?

A. Yes, I do. The NDP should not be just one plant but maybe a combination or portfolio of plants. For instance, the rates could be based on a weighted average of West Valley and the Current Creek project or similar plants. The weights could be used for both the avoided capacity and energy costs. This general concept has been discussed in settlement meetings between the parties.

SUMMARY

Q. What are your final conclusions and recommendations?

A. I conclude:

- That the methods presented by the other parties to the Commission in direct testimony are flawed and should not be adopted without substantial revision.

- That the Commission adopt a method that takes the Company's rudimentary structure, that is, keep the short-run/long-run distinction for determination of capacity costs.
- That the Commission amends Company's method to incorporate the following improvements.
  - In the short run the avoided capacity rate should be determined by the cost of a SCCT and payments should extend over 12 months. If a market value for summer peak capacity can be derived then payments at this rate can be paid over six months.
  - Short run energy rates should be calculated during high load hours using a heat rate for a SCCT and using a raw fuel cost obtained from Inside FERC Gas Market Report first of the Month Index for Kern River Opal. For low load hours, the rates would be determined by the lower of the SCCT rate or Palo Verde price index for firm power.
  - Long-run capacity payments are based on the Company's proxy CCCT. There should be no adjustment made to capitalized energy costs.
  - Long-run avoided energy costs will be based on actual fuel cost index and a calculated heat rate that will approximate the heat rate of the proxy CCCT, including duct firing.
  - Witness Griswold's adjustments should be incorporated as per our recommendations and our additional adjustments should be determined for each QF contract.

- That the Commission should order a study group to investigate a more practical method to determine avoided costs. The group should be given the mission to investigate both the differential revenue requirement method and an "ideal" proxy method. Hopefully, consensus can be reached on the best method, if not then the Commission can make a determination.

Q. Does this conclude your testimony?

A. Yes.