BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF AN IRP BASED AVOIDED COST METHODOLOGY FOR QF PROJECTS LARGER THAN 1 MEGAWATT	Docket No. 03-035-14 DPU Exhibit 1.0

Direct Testimony of

Artie Powell

Division of Public Utilities

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LARGE QF PRICING METHODOLOGY
DOCKET NO. 03-035-14

Q: Will you please state your name, employer, and business address?

A: My name is Artie Powell; my business address is 160 E 300 S Salt Lake City, Utah, 84114; I am employed by the Utah Division of Public Utilities ("Division") as a technical consultant and the acting manager of the energy section.

Q: Would you please summarize your educational and work experience for the record?

A: I have a doctorate degree in economics from Texas A&M University and have taught economics and statistics at the university level for over ten years. I am currently an adjunct professor at Weber State University. I have been employed at the Division full time since 1996. I have also attended various seminars or conferences dealing with a wide range of regulatory topics. In addition, I have completed NARUC's basic and advanced regulatory studies programs at Michigan State University. While at the Division, I have worked on a variety of energy and regulatory matters including, cost of capital, QF and special contracts, and resource acquisition.

Q: Are you testifying on behalf of the Division?

A: Yes, I am.

Q: What is the purpose of your testimony?

A: As the acting manager of the energy section I will serve as the policy witness for the Division and introduce the Division's other witnesses. I will also provide some general testimony on avoid costs methodologies and debt equivalence of purchase power agreements ("PPAs").

Q: Will you please summarize your testimony and the Division's recommendations?

A: In my testimony, I discuss some the advantages and disadvantages of using a proxy model to calculate a utility's avoided costs. I also discuss the issue of imputed debt. Ms. Andrea Coon will also discuss the methodology proposed by PacifiCorp to calculate avoided costs and the Division's recommendations. Dr. Abdinasir Abdulle discusses the green tags related to renewable qualifying facilities (QF). The Division's recommendations are as follows:

1. In general, the Division supports the use of a differential revenue requirement method for calculating the Company's avoided costs. Therefore, the Division recommends that the Commission adopt PacifiCorp's proposed DRR method as a permanent methodology for calculating Avoided Costs for large qualifying facilities (QF) between 3 and 100 MWs. For QFs greater than 100 MW, the Division recommends adoption of PacifiCorp's proposal of having the QFs compete in an RFP for its capacity payment.

2. Because payments for green tags are intended to compensate for the environmental attributes of renewable generation and therefore provides an incentive to develop renewable resources, it is the Division's position that contracts for the sale of QF capacity and energy entered into pursuant to PURPA should not transfer the ownership of green tags should stay with the QF.
3. Finally, while the Division believes that PPAs may impose a cost on the utility on the utility, these costs are difficult to evaluate. Therefore, the Division recommends that the Commission adopt PacifiCorp's proposal for debt-imposed costs from QFs using a minimal risk factor of 15%.

Q: Would please explain what you mean by avoided costs?

A: Conceptually, avoided costs can be defined as "the incremental costs of generating and delivering electric power that will not have to be incurred if an alternative resource(s) is added to a utility's resource mix." Put another way, "avoided costs are the net savings *over the long run* in moving from a *least-cost ('optimal') plan* in the absence of the alternative resource under consideration to a least-cost plan inclusive of the alternative resource under consideration."[1]

Q: How are avoided costs typically calculated?

A: All avoided cost methodologies "are based on finding the difference in revenue requirements that would result from including the alternative resource in a utility's resource mix, versus not doing so." (Tellus Report, p. II-1) In particular

[1] "Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities," Tellus Institute, September 1995, pp. I-4, 6. (Hereafter referred to as the "Tellus Report").

are the so called proxy plant and differential revenue requirements ("DRR") methods.

Q: Would explain what you mean by the proxy plant method?

A: The proxy plant method assumes that an alternative resource, a QF for example, will avoid the costs of a proxy plant, such as, a combined cycle combustion turbine or CCCT. Among other factors, the method may call for consideration of the utility's load and resource balance, the proxy plant's capital and fuel expense, and market purchases. PacifiCorp's Schedule 37, which is a posted price for small QFs, is an example of a proxy plant methodology.

Q: Would you explain what you mean by the DRR method?

A: The DRR method is, as the name implies, the difference in the utility's revenue requirement from two runs of a given model, one run without the alternative or QF resource in the utility's resource mix, and another run with the alternative resource in the mix. These runs would ideally be done using a production dispatch model (such as PacifiCorp's GRID model).

Q: Do you know of any general principles for choosing between the two methods?

A: The principal of parsimony known as Ockham's Razor[2] would suggest that if two

[2] William of Ockham 14th century (c. 1285-1349) English logician and Franciscan friar. While numerous versions of Ockham's Razor have been proffered over time, the most frequent formulations in Ockham's writings are "'plurality is not to be assumed without necessity' and 'What can be done with fewer

or more models or methods yield essentially the same results, the less complex of the methods is preferable.

Furthermore, despite arguments to the contrary, I believe it is important to achieve the highest degree of accuracy in avoided costs as possible. As Tellus explains,

> The importance of accurate avoided cost calculations in achieving the objectives of IRP *cannot* be overstated. Avoided costs are at the heart of the IRP process, or the more general process of resource evaluation, because they provide the *key benchmark* against which costs of alternative demand- and supply-side resources are evaluated. Inaccurate avoided costs estimates can greatly undermine the process of selecting appropriate resources for inclusion in an IRP, or any least cost resource portfolio, including portfolios consisting of market based power controls. If avoided costs are too high, they can result in uneconomic alternative resource procurement, as well as excessive costs to the utility and its ratepayers from over-procuring the alternative resource. If avoided cost estimates are too low, the result will be uneconomic resource procurement and excessive costs to the utility and its ratepayers from conventional supply-side resources. This result will also inappropriately discourage alternative supply-side resource development. The underdevelopment of alternative resources will cause the potential financial, environmental, risk reduction, and other economic benefits of these resources to utilities, their ratepayers, and society to be lost." (Tellus Report, pp. I – 8, 9)

Q: Do the methods yield the same results?

A: According to some industry experts, the DRR methodology, while more complex than a proxy plant methodology, yields superior results and, therefore, should be the basis of avoided cost calculations. For example, the Tellus Report "strongly

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[assumptions] is done in vain with more.'" (Dorothy Rose Blumberg, *Whose What?,* [Holt, Rinehart and Winston; New York, New York], 1969, pp. 118-119.)

recommends the differential revenue requirements approach because it is the most accurate." The report goes on to say,

> In most instances, the proxy plant methodology is only a crude approximation for calculating avoided costs. The simplifying assumption that the two least cost plans – one with and one without the alternative resource – will differ only in the construction and operation of a single proxy plant is almost never likely to be true. Typically, the difference between the two optimal resource plans will be attributable both to <u>delays</u> in a series of new generating units by varying amounts of time, as well as to changes in the <u>mix</u> of new baseload, cycling, and peaking units. (Tellus Report, p. II - 3)

Q: Are there any conditions under which the proxy plant method would be a reasonable alternative to the DRR method?

A: In fairness, a proxy plant method has the advantage of being much simpler than the DRR and can yield accurate results if three conditions are met:

1. The operating characteristics of the proxy plant closely match those of the alternative resource being evaluated;
2. The alternative resource exactly replaces the entire capacity and energy of the proxy plant; and
3. The alternative resource does not significantly affect other plant additions or system operations. (See Tellus Report, p. II-7)

Q: In your opinion, are these conditions likely to be met in a proxy plant methodology?

A: In general, I think it is unlikely that these conditions can be satisfied with a proxy plant methodology. For example, the third condition requires that no other utility resources or operations be significantly affected by the presence of the alternative resource. From what I understand, the introduction of an alternative resource will affect other utility resources and operations and is the basis (at least in part) for Tellus' support of the DRR method.

Furthermore, these conditions obviously imply some general limitations of the proxy plant method. Namely,

1. If the operating characteristics of the proxy plant do not closely match those of the alternative resource, the resulting estimated avoided costs may be far from the resource's true avoided costs. Because of the interdependence of capacity and energy costs and the complexities of system dispatch, this can be true even if the avoided <u>capacity</u> costs are accurate. (Tellus Report, p. II-9 and Section III)

2. If the alternative resource does not exactly replace (avoid) the proxy plant, then the alternative resource will be credited with an inaccurate avoided cost. If the alternative resource's capacity is less (greater) than that of the proxy plant, the avoided costs will be too high (low). (Tellus Report, pp. II-9, 10)

Additionally, attempting to satisfy the requirements outlined above may lead to "re-inventing" the proxy model each time a QF applies for pricing. For example, under Schedule 37 pricing for small QFs, which uses a proxy plant methodology, part of the capacity payment is folded into the energy payment. If the small QF operates in a manner similar to the (Schedule 37) proxy plant, the QF should be indifferent to this treatment. If the small QF operates differently (i.e., offers less capacity) from the proxy plant, this treatment mitigates the risk of overpayment to the small QF. Furthermore, the pricing model for Schedule 37 is divided into sufficiency and deficiency periods. For larger QFs, these two factors alone would require re-building the proxy model each time a QF applies for pricing possibly leading to protracted debates, negotiations and litigation. Additionally, changing the proxy model for each QF could potentially leave the Division and Commission open to charges of discriminatory treatment of different QFs.

Q: Have the interveners in this docket proposed a viable proxy plant methodology?

A: Conceptually, certain interveners have discussed a proposed method, however, at this time no viable proxy plant model has been provided to other parties in this docket for examination.

Q: If a proxy plant method has not been proposed at this time, how would you recommend the Commission proceed in this matter?

A: I suspect that one or more of the interveners will propose and support a proxy plant method in direct testimony. This possibility was discussed in several of the meetings held under this docket leading up to the deadline for filing testimony. If a proxy plant method is actually proposed, it is the Division's considered position that the Commission should evaluate the viability of the model based on the criteria I outlined above. Namely, the model's complexity and accuracy should be compared to that of the method proposed by PacifiCorp.

In this regard, the Division has, on several occasions, expressed the believe that (1) it is incumbent on those proposing such a method to demonstrate that the proxy plant model yields, when using the same set of assumptions as PacifiCorp's DRR method, the same (or very similar) results as PacifiCorp's DRR method; and (2) that the proxy plant model take into account minimum resource and operating characteristics from PacifiCorp's actual resource mix and system operations so as not to require re-building the model for each QF.

In the absence of such a demonstration, the Division supports the Company's proposed methodology as filed with the modifications discussed in our testimony.

Q: PacifiCorp is proposing adjusting the price paid to a QF based on the assumption that purchase power agreements (PPAs) impose a cost on the utility. Could you explain the Division's position on this matter?

A: PacifiCorp has proposed an adjustment to QF contracts depending on whether the contract is considered to be an operating or capital lease. If a contract is classified as a capital lease, the contract is considered to be a debt instrument and the capacity payments would be reflected directly on PacifiCorp's balance sheet. If, on the other hand, the contract is classified as an operating lease, rating agencies may reflect a portion of the capacity payments in a utility's financial ratios for the purpose of setting credit quality or ratings. For example, in a report on its rating methodology Moody's Investor Service states,

> Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner … this charge covers the portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments cover the debt service and are made irrespective of whether the utility requires the IPP to generate. … The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station.[3]

Similarly, a report by Standard & Poor's states

> Standard & Poor's Rating Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitialized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.[4]

Clearly, whether the QF contract is classified as a capital or operating lease, there theoretically appears to be a cost imposed on the utility and, if so, should be recognized in setting the avoided costs for each QF contract. However, at least in the case where the PPA is determined to be an operating lease, calculating this cost maybe somewhat problematic.

Q: Would you explain what you mean by "problematic"?

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[3] Moody's Investor Service, "Rating Methodology: Global Regulated Electric Utilities," March 2005. p. 9.

[4] Standard & Poor's, *Utilities & Perspectives,* May 12, 2003, p. 2.

A: In a report prepared by the Energy Information Administration the authors conclude, "Overall, based on the available financial data using two different approaches, there is no conclusive evidence that power purchases from nonutility generators raised the cost of capital to the utilities which purchase the electricity."[5] Likewise, in a report from Lawrence Berkeley Laboratory the authors conclude, "Our principle finding is that we cannot detect any evidence to support the debt-equivalence hypothesis."[6] While both these reports pre-date the California energy crises and the Enron debacle, these findings are arresting.

Q: Do rating agencies recognize the difficulty in measuring the affects of PPAs on the utility's cost of capital?

A: This measurement difficulty appears to be recognized in Moody's Investment Service's approach to PPAs:

> In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the *subjective nature* of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change.[7]

Q: How do the rating agencies account for the impact of PPAs on the utility?

[5] "Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities," report prepared by the Energy Information Administration, June 1994. (DOE/EIA-0580; http://www.eia.doe.gov/cneaf/electricity/pub_summaries/finance.html).

[6] Edward Kahn, Steven Stoft, and Timothy Belden, "Impact of Power Purchases from Nonutilities on the Utility Cost of Capital," Energy and Environment Division, Lawrence Berkeley Laboratory, March 1994 (LB-34741; UC 350).

[7] Moody's Investor Service, p.10. (Emphasis added).

A: One method Moody's proposes to use is the "NPV of the stream of PPA payments to the adjusted obligations of the utility." Given the discussion by Moody's, I interpret this to refer to the NPV of the capacity or fixed obligations under the PPA, which is similar to the methodology used by Standard & Poor's. As I mentioned above, Standard & Poor's applies a risk factor to the NPV of the capacity payments of a PPA. Standard & Poor's has indicated that, in general, "a 50% risk factor is appropriate for long-term commitments."[8]

Q: Is Standard & Poor's risk factor constant?

A: No, both Moody's and Standard & Poor's indicate mitigating factors that they consider in adjusting any financial risk factors. For example, Moody's indicates that in deciding which combination of methodologies to use it will consider "the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and materiality of the PPA obligation to the overall cash flows of the utility in assessing the affect of the PPA on the credit of the utility."[9] Similarly, Standard & Poor's indicates that, "For utilities in supportive regulatory jurisdictions … a risk factor as low as 30% could be used."[10] In a more recent report, Standard & Poor's states, "The passage of SB 26 implies that a lower risk factor will be utilized for future Utah PPAs that fall under the protection of the

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[8] Standard & Poor's, May 12, 2003, p. 2.

[9] Moody's Investor Service, p.10.

[10] Standard & Poor's, May 12, 2003, p. 3.

new legislation."[11] Like Moody's, Standard & Poor's also indicates that the ability to recover the costs associated with the PPA is another mitigating factor.

Standard & Poor's indicates that other mitigating factors could indicate even lower risk factors. For example, Standard & Poor's states, "In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated."[12] While PacifiCorp is not just a distribution company, Standard & Poor's statement makes it clear that the emphasis is on the risk of recovery. In this regard, the Division notes that Utah QFs are pre-approved through the regulatory process and, therefore, pose little risk of non-recovery.

Furthermore, in a white paper prepared by the Electric power Supply Association ("EPSA"), a Senior Vice President for Standard & Poor's is quoted, "We did not attempt to compare the risks of purchasing with the risks of building. Suffice it to say that adding capacity is a risk regardless of how it is met."[13] The EPSA paper goes on to say, "This underscores the fact that it is difficult to ascribe any particular utility's credit rating, good or bad, to a single factor, such as the size of the utility's purchased power obligations."[14] For example, in the studies

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[11] Standard & Poor's, *Ratings Direct*, May 5, 2005.

[12] Standard & Poor's, May 12, 2003, p. 3.

[13] Curtis Moultan, quoted in, Electric Power Supply Association, "Buy or Build: Assessing the Impact of Power Purchase Agreements on Utility Credit Ratings and Balance Sheet Integrity," White Paper #2, July, 2004.

[14] EPSA, White Paper #2, p. 4.

conducted by Lawrence Berkeley Laboratory and the Energy Information Administration, the researchers conclude that relative to the debt-equivalence hypothesis, "we find more evidence to support the notion that utility construction raises the cost of capital than that [PPAs] do."[15] Apparently, as Hamlet said in Shakespeare's play of the same name, "There are more things in heaven and earth, Horatio, than are dreamt of in your philosophy."[16]

Q: What is PacifiCorp's proposal to calculate the affect of PPAs on its capital costs?

A: PacifiCorp, following the general guidelines indicated by Standard & Poor's, proposes using 50% risk factor applied to the present value of the capacity payments discounted at 10%. The cost of the imputed debt is then calculated as the cost of the incremental equity necessary to bring the utility's capital structure back to its original (i.e., pre-imputed debt) level. An example of PacifiCorp's proposed methodology is explained in the direct testimony of PacifiCorp's witness Mr. Shah.

Q: With respect to the debt equivalence issue what is the Division's recommendation?

A: It is the Division's position that debt arising from PPAs may affect, directly or indirectly, the cost of capital of the purchasing utility. That is, a utility may need

[15] Edward Kahn, et. al., p. 30.

[16] William Shakespeare, *Hamlet*, Act 1, Sc. 5, Lines 166-67.

to infuse additional equity to re-balance its capital structure to offset the additional debt imposed directly or indirectly by a PPA. In the case of direct debt, when a PPA is determined to be a capital lease, we support the Company's proposed treatment. However, when a PPA is determined to be an operating lease, and the debt is imputed by rating agencies for the purpose of setting credit ratings, we recommend a more conservative approach than that proposed by PacifiCorp. Given the ambiguities of the actual impact or affect on the utility's cost of capital, we recommend the use of a minimal risk factor of 15%. Additionally, the Division recommends that,

1. The debt-equivalence adjustment should apply on an incremental basis to all QFs excepting those which fall under Schedule 37; and

2. The Commission order PacifiCorp to cooperate with the Division in replicating and updating the Lawrence Berkeley Laboratory and the Energy Information Administration studies.

Q: Does this conclude your testimony?

A: Yes it does.