WITNESS CCS – 2

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application	**:**	**DOCKET NO. 03-035-14**
of PacifiCorp for an Order	**:**	**PREFILED DIRECT TESTIMONY OF**
Approving Avoided Cost Rates	**:**	**PHILIP HAYET**
	:	**FOR THE COMMITTEE OF**
	:	**CONSUMER SERVICES**

12 April 2004

DIRECT TESTIMONY OF PHILIP M. HAYET

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Philip M. Hayet, 215 Huntcliff Terrace, Atlanta, GA, 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant and I am the owner of the firm Hayet Power Systems Consulting, which provides utility rate, planning, and economic consulting services. I am appearing in this proceeding as a witness for the Committee of Consumer Services ("Committee").

Q. PLEASE DESCRIBE BRIEFLY THE NATURE OF THE CONSULTING SERVICES PROVIDED BY HAYET POWER SYSTEMS CONSULTING.

A. Hayet Power Systems Consulting provides consulting services in the electric utility industry. The firm provides expertise in system planning, load forecasting, resource analysis, production cost modeling and utility industry policy issues.

I. QUALIFICATIONS

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. CCS Exhibit 2.1 describes my educational background and work experience within the utility industry. Briefly, I received a Bachelor's degree from Purdue University and a Master's degree from the Georgia Institute of Technology, both in Electrical Engineering. I have more than twenty years of experience in the electric utility industry in the areas of generation resource planning, economic analysis, and rate analysis. In 1995 I formed Hayet Power Systems Consulting and my clients have included global power plant developers, multinational oil and gas exploration and power development companies, state energy offices, staffs of public utility commissions, consumer advocate offices, law firms, and international consulting firms.

Q. HAVE YOU PARTICIPATED IN ANY REGULATORY PROCEEDINGS THAT HAVE INVOLVED PACIFICORP?

A. Yes, I testified in PacifiCorp's ("the Company's") Rate Case Docket No. 97-035-01, in which I testified in support of the Net Power Cost Stipulation ("1997 Stipulation") on behalf of the Division of Public Utilities ("Division") and the Committee. In PacifiCorp's 1999 Utah rate case (Docket No. 99-035-10), I assisted Committee witness, Mr. Randall Falkenberg, who testified concerning net power cost issues. I testified in 2001 in PacifiCorp's rate case, Docket No. 01-035-01, regarding PacifiCorp's net power cost model and transmission modeling issues. I participated in PacifiCorp's 2003 rate case proceeding, again analyzing production cost issues, and I assisted the Committee with Settlement Discussions. I have assisted Mr. Randall Falkenberg in a number of other PacifiCorp proceedings in other states involving net power cost issues. Finally, I have provided assistance to the Committee in several proceedings including the Currant Creek Certification Case, PacifiCorp's IRP, the Hunter Replacement Power Outage Case (Docket No. 01-035-23), and the Gadsby Certification Case (Docket No. 01-035-37).

Q. HAVE YOU PARTICIPATED IN ANY PREVIOUS AVOIDED COST MATTERS THAT INVOLVED PACIFICORP?

Yes. I first became involved in PacifiCorp's avoided cost proceedings around September 2002, when the Company filed an update to its Schedule 37 avoided cost. Since that time I have assisted the Committee with every avoided cost proceeding that has taken place. I was also a participant in work group meetings that PacifiCorp held concerning Schedule 37 and 38 avoided costs. I have also been involved in PacifiCorp's IRP public input processes that began in 2002, and are still ongoing today.

II. SUMMARY

Q. PLEASE PROVIDE BACKGROUND CONCERNING PACIFICORP'S CURRENT SCHEDULE 38 AVOIDED COST PROCEEDING.

Prior to 2002, PacifiCorp only had in place a standard tariff (Schedule 37) for Qualifying Facilities (QF) that are up to1 MW in size. In recent years, potential QF developers have expressed considerable interest in developing a tariff for larger QFs that want to be able to sell capacity and energy to PacifiCorp. These QF developers desired to have a clear process for determining the rate that a QF would likely be paid, as well as the steps required to obtain a purchase power contract. PacifiCorp filed for its first Schedule 38 tariff on 7 October 2002 and requested that it become effective on 7 November 2002. In response to requests that more time was needed to evaluate PacifiCorp's filing, the Commission suspended the schedule on 12 November 2002, and required PacifiCorp to respond to various interested parties' concerns. A major concern was that PacifiCorp's Schedule 38 Tariff did not clearly state the methodology that it would rely on to calculate avoided capacity and energy costs.

PacifiCorp refiled its Schedule 38 Tariff in January 2003, and then on 24 February 2003, the Commission issued an order adopting PacifiCorp's filing. However, in adopting the filing, the Commission required PacifiCorp to file within 90 days both an avoided cost methodology for developing indicative QF purchase prices, and a generic power purchase agreement (PPA). The Commission also ordered PacifiCorp to convene a work group with interested parties to help develop the avoided cost methodology and generic PPA.

On 27 May 2003, after having convened a number of work group meetings, the Company filed its proposals with the Commission. In that filing, the Company outlined its proposed avoided energy cost methodology, but did not clearly explain how avoided capacity payments would be calculated and under what circumstances they would be paid to large QFs. Both the Committee and the Division objected to the fact that PacifiCorp's proposal lacked a specific methodology for determining avoided capacity costs. On 24 September 2003, the Commission ordered PacifiCorp to reconvene the QF working group to resolve the capacity payment issue as well as other issues of concern to the parties. It also ordered PacifiCorp to refile for approval within 60 days a revised methodology for determining indicative avoided cost rates. PacifiCorp met once again with the parties, and then on 3 February 2004, PacifiCorp filed its proposed methodology calculation for Schedule 38 avoided costs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The Committee has asked me to analyze PacifiCorp's filing and to make recommendations regarding PacifiCorp's proposed avoided cost methodology.

Q. PLEASE SUMMARIZE THE COMMITTEE'S RECOMMENDATIONS.

A. The Committee recommends the following:

1. Avoided Energy Costs – For purposes of calculating avoided costs for Schedule 38, the Committee recommends that PacifiCorp use the differential revenue requirement methodology using a production cost model for the entire planning horizon, not just for the near-term period. This is the same methodology that the Company proposed in its 27 May 2003 Schedule 38 filing to the Commission that it referred to as the "IRP Approach."

2. Avoided Capacity Costs – The Committee supports a "proxy" methodology for determining avoided capacity costs, but recommends that avoided capacity costs be based on the type of capacity resource that is to be deferred in each year. In years when Combined Cycle Combustion Turbine (CCCT) resources are planned to be built, CCCT capacity costs should be the basis of computing avoided capacity costs. The same proxy process should apply to coal units, wind units, etc.

3. PacifiCorp's Firm QF Operating Reserve Adjustment – As the Committee recommends the use of the differential revenue requirement methodology, proper production cost modeling eliminates the need for a 7% operating reserve adjustment.

4. PacifiCorp's Dispatch QF Adjustment – The Committee recommends that PacifiCorp's adjustment be modified based on our recommendation to use the differential revenue requirement methodology. Using this methodology, QF characteristics will be specifically modeled and the penalty assessed should be

developed based on those characteristics, versus an arbitrary QF that PacifiCorp selects in a "one size fits all" approach.

5. PacifiCorp's Integration Cost Adjustment- The Committee recommends eliminating PacifiCorp's integration cost adjustment as the integration costs should be captured within the production cost modeling. However, should the Commission find that it is too difficult to use a production cost model (despite the fact that PacifiCorp has already done so), then the Committee recommends a less costly adjustment.

6. PacifiCorp's Variable O&M Costs Conversion – PacifiCorp converts Variable O&M (VO&M) costs from $/MWh to $/kW-yr and back to $/MWh. In doing so it uses inconsistent capacity factor assumptions, resulting in a converted VO&M cost that is 85% below the value that it started with. This needs to be corrected.

7. PacifiCorp's Pre-PURPA QF Adjustment – PacifiCorp has stated its intentions to apply an adjustment to avoided costs for QFs built prior to 9 November 1978, when PURPA first went into effect. However, the Company did not state the methodology it would use to make the adjustment. The Committee recommends that the Company file a methodology for all parties to review and comment on.

8. Common Schedule 37 and 38 Recommendations – The Committee has five adjustments to PacifiCorp's avoided cost calculations that are common to Schedule 37 and 38. A list of those adjustments is provided in Section IV of my testimony and discussed in greater detail in the Committee's Schedule 37 memo to the Commission dated 9 April 2004. For reference purposes, the Schedule 37 memo is attached as CCS Exhibit 2.2.

III. ANALYSIS

Q. ARE YOU AWARE THAT PACIFICORP HAS FILED TWO DIFFERENT METHODOLOGIES FOR CALCULATING AVOIDED COST RATES IN THIS DOCKET?

A. Yes. In addition to its current 3 February 2004 filing, PacifiCorp, in a prior 27 May 2003 filing, proposed a different methodology for computing avoided cost rates. In that filing, the Company referred to its avoided cost methodology as the "IRP-based methodology." The methodology that PacifiCorp proposed in the latest filing has some similarity to the IRP methodology in the first few years (2004 through mid 2007), but in the longer term (mid 2007 through 2028) the methodologies sharply differ.

Q. PLEASE EXPLAIN THE IRP METHODOLOGY THAT THE COMPANY PROPOSED IN ITS 27 MAY 2003 FILING.

A. PacifiCorp's provided a reasonable explanation of the methodology in its application to the Commission. It stated:

> The IRP-based methodology which has been discussed in the work group, and which the Company proposes herein, will determine avoided costs using two computer simulations of long-run resource expansion plans. In the first, or "base case" simulation, all costs will be calculation on an annual basis. In the second, or "incremental cost" simulation, a resource (the specific Large QF that is the subject of the calculation) will be added to the base case at zero cost, and the expansion plan will be recalculated. The net present value of the difference in total revenue requirement streams of the two simulations will be the avoided cost of the new resource. That net present value would then be adjusted to a payment stream that increases at inflation over the life of the QF contract. The resulting avoided costs will equal the sum of the energy value assumed to be produced by the QF, the change in the system dispatch costs (positive and negative) and, if applicable, the fixed and variable costs of a delayed or displaced planned resource, less the energy value that would otherwise be available from the delayed or displaced resource. In selecting the resource to be delayed or displaced by the QF, the Company will consider whether the capacity, energy, dispatchability, and plant commercial operation dates, are substantially equivalent. Resources included in the Integrated Resource Plan to provide diversity and balanced risk will not be considered for delay or displacement unless the QF provides similar benefit.

Q. WHAT POSITION DID THE DIVISION AND COMMITTEE TAKE REGARDING PACIFICORP'S METHODOLOGY?

A. In the Commission's order issued 24 September 2003, the Commission noted that both the Committee and the Division were generally supportive of the avoided energy cost calculation methodology, however both parties objected to the fact that PacifiCorp declined to specify its methodology for determining avoided capacity costs.

Q. WHAT DECISION DID THE COMMISSION REACH CONCERNING PACIFICORP'S 27 MAY 2003 FILING?

A. The Commission ordered the Company to reconvene the working group to address, in particular, the avoided capacity cost issue. The Commission also required PacifiCorp to refile its avoided cost methodology within 60 days; PacifiCorp's latest application filed on February 3, 2004 met that requirement.

Q. PLEASE EXPLAIN THE NEW METHODOLOGY THAT PACIFICORP HAS FILED WITH THE COMMISSION IN ITS 3 FEBRUARY 2004 APPLICATION.

A. The new avoided cost methodology is virtually identical to what PacifiCorp filed in its recent Schedule 37 application for QFs of up to 1 MW in size, with some adjustments based on the specific characteristics of an individual QF. With respect to calculating avoided energy costs, the current methodology combines a differential revenue requirement approach with a proxy plant approach. The differential revenue requirement approach is actually similar to what PacifiCorp proposed in its 27 May 2003 Schedule 38 filing to the Commission, which was known as the IRP methodology. The differential revenue requirement approach is used during the resource sufficiency period (2004 – mid 2007), while a proxy plant methodology, based on the cost of operating a CCCT, is used during resource deficiency period (mid 2007 – 2028).

With respect to calculating avoided capacity costs, the current methodology relies on the capacity costs that are assumed to be associated with market purchases during the summer period. During the sufficiency period, PacifiCorp uses the cost of a Simple Cycle Combustion Turbine (SCCT) unit as a surrogate for the market purchase cost. However, capacity payments are only made for the three summer months of the year. During the deficiency period, avoided capacity costs are based on the capacity costs of a CCCT unit, and capacity payments are made every month of the year.

Q. ARE THERE ANY OTHER DIFFERENCES IN THE DIFFERENTIAL REVENUE REQUIREMENT METHODOLOGIES BETWEEN THE MAY 2003 AND FEBRUARY

2004 FILINGS?

A. Yes. PacifiCorp's May 2003 IRP approach relied on the Prosym model and database used in the 2003 IRP. The differential revenue requirement methodology filed in February 2004 was developed using the GRID production model, with a database that likely was similar to the IRP database, although not identical.

Q. WHAT IS THE COMMITTEE'S OPINION OF PACIFICORP'S LATEST METHODOLOGY?

A. The Committee is concerned that the Company's proposed avoided cost methodology may be satisfactory for computing avoided costs for small QFs up to 1 MW in size, but I do not believe it is reasonable for QFs larger than 1 MW.

Q. COULD PACIFICORP'S PROPOSED AVOIDED COST METHODOLOGY PRODUCE INACCURATE AVOIDED COST RESULTS?

A. Yes. PacifiCorp's methodology predetermines that for most years the avoided energy costs would only be based on the cost of a gas-fired CCCT. That assumption may be acceptable for a small QF that would generally avoid only the highest cost resource on PacifiCorp's system. However, larger QFs would displace not only PacifiCorp's most expensive resource, but also some of PacifiCorp's less expensive resource (eg coal energy).

For instance, a large QF that operates within an industrial facility may have excess generation available at night that it wants to sell to the utility as QF energy. In order to accept the QF energy, PacifiCorp may be forced to turn down some of its base load coal-fired generation, along with some gas-fired generation, to minimum operating levels. In that situation, the true value of the avoided energy cost should be partially weighted by the coal energy cost and partially weighted by the more expensive gas fired energy cost. Since PacifiCorp's avoided energy cost methodology for most of the years is based on the cost of a gas-fired CCCT proxy, the Company's assumption is that the CCCT cost is the only energy cost that would be avoided by the QF. This would have the effect of overstating PacifiCorp's avoided energy costs.

Q. DOES THE COMMITTEE AN ALTERNATIVE RECOMMENDATION FOR A METHODOLOGY TO CALCULATE AVOIDED ENERGY COSTS?

A. Yes. The Committee recommends that the Company should use the differential revenue requirement methodology to calculate avoided energy costs, as it proposed in its 27 May 2003 Schedule 38 filing to the Commission. Although the Commission's 27 September 2003 Order did not explicitly adopt that methodology for calculating avoided energy costs, it seems the Commission was satisfied with the Company's avoided energy cost approach. In addition, the participants to the QF work group were also generally supportive of the differential revenue requirement methodology for determining avoided energy costs. In fact, the work group had moved on to providing input on the generic PPA.

Q. GIVEN THE SUPPORT FOR THE DIFFERENTIAL REVENUE REQUIREMENT METHODOLOGY, WHAT OTHER POSSIBLE REASON MIGHT PACIFICORP HAVE FOR OPPOSING IT?

A. Other than the Company's desire to streamline both its Schedule 37 and Schedule 38 avoided energy cost calculations using the same methodology, I can only recall one other issue that arose during the QF working group meetings that may be of concern to PacifiCorp. It was known as the "double counting of capacity issue." PacifiCorp asserted that the differential revenue requirement methodology would result in an overpayment of capacity costs to QFs.

Q. PLEASE BRIEFLY DESCRIBE PACIFICORP'S CONCERNS RELATING TO THE DOUBLE COUNTING OF CAPACITY ISSUE.

A. PacifiCorp was concerned that when it either sells or buys power in the market, the price for electricity includes not only an energy cost component, but also a capacity cost component disguised as an energy cost. For instance, if PacifiCorp were to contract for a 5 (day) by 16 (hour) strip of energy for delivery next week, PacifiCorp contends that embedded in the quoted energy price is also a capacity charge. If avoided energy costs are computed based on a methodology that assumes PacifiCorp will make market energy purchases, PacifiCorp argues that it will end up overpaying capacity costs to a QF.

Q. DO YOU AGREE THAT THERE MIGHT BE AN OVERPAYMENT OF AVOIDED CAPACITY COSTS THAT MIGHT OCCUR USING THE DIFFERENTIAL REVENUE REQUIREMENT METHODOLOGY?

A. No, I do not. First, I have never heard of a utility other than PacifiCorp expressing this concern. Most utilities that I am aware of have relied on production costing models using a “two run” differential revenue requirement approach to develop avoided energy costs, and none that I recall ever raised a concern that using a production cost model to develop avoided energy costs would lead to overpayments of capacity costs. Second, just because market energy prices appear to be above the cost to actually generate the energy, I would not consider the premium to be a capacity charge in the context of calculating avoided energy costs. In this case, I view the premium as simply caused by the normal market forces of supply and demand. Because the QF allows the utility to avoid the higher energy costs during the summer, it should be entitled to higher energy cost payments during the summer. Third, PacifiCorp never voiced a concern that there may be a double counting of capacity when it uses a differential revenue requirement approach for the summer 2004- 2007 period.

Q. DOES THE COMMITTEE BELIEVE THAT PURPA’S RATEPAYER INDIFFERENCE STANDARD MAY TIE IN WITH PACIFICORP’S CAPACITY COST DOUBLE PAYMENT ISSUE?

A. Even if we could be persuaded that the double counting of capacity issue is legitimate, we don’t believe that ratepayers would have to pay any higher costs if PacifiCorp were to use a differential revenue requirement methodology. The differential revenue requirement methodology requires two production cost runs, one run that includes a zero cost QF and one without the QF. In the run with the QF, if the QF enables PacifiCorp to avoid the costs associated with a market purchase, PacifiCorp could pay the QF exactly what it would have paid for the market purchase and ratepayers should be completely indifferent. Therefore, ratepayers, should be unaffected whether PacifiCorp purchases energy from other wholesale suppliers or QFs.

Q. IS THERE ANY OTHER RATIONALE FOR USING THE DIFFERENTIAL REVENUE REQUIREMENT METHODOLOGY?

A. Yes. I would agree completely with Mr. Tallman's statement on page 2 of his testimony at line 16, "…an avoided cost methodology should be able to keep pace with the Company's changing load and resource needs, as well as with changing market conditions." I question whether PacifiCorp's proxy methodology that relies on a gas-fired CCCT for the entire planning period will keep pace with the Company's changing loads and resource needs. If the Company relies on a differential revenue requirement methodology for the entire period, it can properly model the different resources (CCCT units, coal units, and renewable units) that PacifiCorp will build or acquire over time, consistent with its IRP.

Q. IS THE COMMITTEE ALSO RECOMMMENDING A DIFFERENT APPROACH TO CALCULATE AVOIDED CAPACITY COSTS COMPARED TO PACIFICORP'S METHODOLOGY?

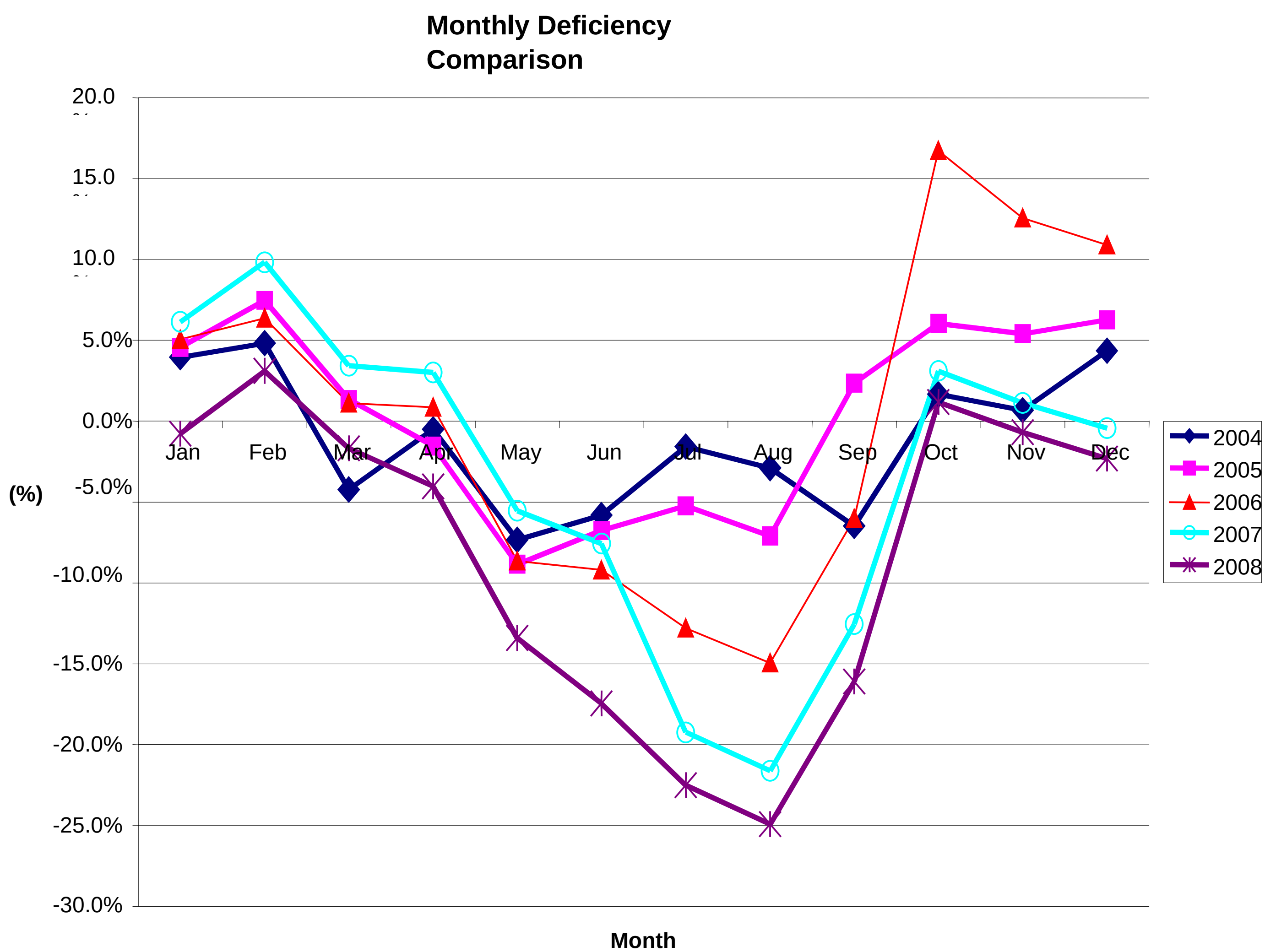
A. Yes. PacifiCorp proposes to develop avoided capacity payments in one manner during the sufficiency period and in another manner during the deficiency period. During the sufficiency period (2004-mid 2007), PacifiCorp calculates avoided capacity costs based on the cost to purchase summer capacity, which, in PacifiCorp's analysis, is developed using the cost of a SCCT unit as a surrogate. During the sufficiency period, PacifiCorp also proposes to make avoided capacity payments for only the three summer months of the year, which corresponds to the period PacifiCorp believes that loads exceed capacity resources.

During the deficiency period, which begins mid 2007 and continues through 2028, PacifiCorp makes avoided capacity cost payments based on the cost of a CCCT unit with the assumption that the capacity payments are made for every month in the year.

Q. DURING THE SUFFICIENCY PERIOD (2004 THROUGH MID 2007) HOW MANY MONTHS OF THE YEAR DOES THE COMMITTEE RECOMMEND THAT QFS RECEIVE AN AVOIDED COST CAPACITY PAYMENT?

A. At a minimum, the Committee recommends that an avoided cost capacity payment be made for six months out of twelve months for each year during the sufficiency period. Figure 1 below shows PacifiCorp's resource sufficiency/deficiency for each month over the 2004-2008 period. A negative value indicates that the Company receives additional capacity resources and that QFs should receive avoided cost capacity payments in these months. Figure 1 clearly demonstrates that during the 2004-2008 period PacifiCorp's annual deficiency is not just limited to the three summer months, but on average a deficiency exists for six months.

Figure 1



Q. EARLIER YOU MENTIONED THAT PACIFICORP'S SCHEDULE 38 AVOIDED COST METHODOLOGY IS VIRTUALLY IDENTICAL TO THE METHODOLOGY IT PROPOSED FOR SCHEDULE 37 AVOIDED COST RATES, WITH SOME ADJUSTMENTS BASED ON THE OPERATIONAL CHARACTERISTSICS OF AN INDIVIDUAL QF. PLEASE DESCRIBE HOW THIS PROCESS OF MAKING ADJUSTMENTS WILL WORK.

A. According to Company witness Roger Weaver, (page 2, line 20), the Company envisions two steps will be required to compute its avoided costs. The first step develops avoided costs that would be paid to a QF having optimum operational characteristics, and the second step adjusts the avoided costs based on specific characteristics of individual QFs. Company witness Bruce Griswold discusses the second step that the Company advocates performing to adjust avoided costs paid to individual QFs.

Q. WHAT IS THE COMMITTEE'S AVOIDED CAPACITY COST RECOMMENDATION FOR THE LONG RUN PERIOD?

A. At this time the Committee recommends that the Commission adopt a relatively simple proxy unit methodology that differs somewhat from the proxy approach proposed by the Company. Specifically, the generation unit planned to be added in a future year, as determined by PacifiCorp's latest IRP, should be the proxy unit for establishing that year's avoided capacity cost. For example, if in 2011, PacifiCorp's IRP calls for the addition of a coal unit, then for that year the proxy unit would be based on the capacity cost of a coal unit. Whereas PacifiCorp's long run methodology relies on the cost of a CCCT unit every year, I believe the Committee's recommended proxy unit is more reasonable methodology because it reflects the costs of the actual units that are planned to be added to PacifiCorp's system.

Q. HOW MANY ADJUSTMENTS DOES PACIFICORP PROPOSE TO MAKE TO THE GENERIC AVOIDED COST CALCULATIONS?

A. PacifiCorp proposes seven adjustments to the standard avoided cost calculations. I will explain the adjustments and describe the modifications recommended by the Committee.

Q. WHAT IS PACIFICORP'S FIRST ADJUSTMENT?

A. Non-Firm Versus Firm Power

PacifiCorp's first adjustment results in no capacity payments made to a QF unless the QF can supply contractually firm power to PacifiCorp. The Committee fully supports this adjustment because it comports with the PURPA principle that the Company should be no better and no worse off for having to purchase power from a QF. If the QF provides non-firm power to the Company, and PacifiCorp is required to make a firm capacity payment, then the Company would make payments greater than the benefits the QF would provide.

The Company has a second adjustment associated with non-firm QF purchases. It recommends reducing the avoided energy cost by 7% based on an operating reserve adjustment during the sufficiency period (Griswold, page 2, line 22). PacifiCorp makes this adjustment because it believes that capacity costs are included in market purchase costs during the sufficiency period, and the 7% adjustment helps to remove those costs. The Committee strongly disagrees with this proposed adjustment.

Given the Company proposes to use a differential revenue requirement approach during the sufficiency period, this issue should not even arise. The lower value that the non-firm QF provides to the PacifiCorp system from an avoided energy cost standpoint should be fully captured in the Company's production cost modeling analysis. There should be no need to make an additional adjustment outside of the model to account for operating reserves.

Q. WHAT IS PACIFICORP'S SECOND ADJUSTMENT?

A. QF Availability During Peak Periods

PacifiCorp proposes that QFs that cannot or will not sell power during peak periods should be penalized by not being paid the avoided capacity payments. If a QF has the understanding in advance that it must be able to supply capacity and energy during peak periods, then the Committee believes it is reasonable to assess an avoided capacity factor penalty if the QF does not deliver during the peak period.

Q. WHAT IS PACIFICORP'S THIRD ADJUSTMENT?

A. <u>PacifiCorp's Rights to Dispatch the QF</u>

PacifiCorp proposes to assess a penalty to QFs that do not provide PacifiCorp with the right to dispatch QF generation on demand. The metric that PacifiCorp proposes to use for assessing this penalty is whether or not the QF adheres to a specific capacity factor that PacifiCorp uses when it develops the avoided costs. During the sufficiency period the capacity factor is assumed to be 100%, and during the deficiency period the capacity factor is assumed to be 85%. If the definition of firm power is understood by both the QF and PacifiCorp to mean that PacifiCorp would have full dispatch rights, then it is reasonable for PacifiCorp to assess a penalty if the QF does not provide the full dispatch capacity at the time of actual operations.

However, the Committee has stated its preference for use of the differential revenue requirement approach for the entire study period, and the Committee also prefers that the specific characteristics of a QF be modeled when avoided costs are calculated. If the QF only promises a 60% capacity factor, then the standard that it should be measured against is a 60% capacity factor when the QF energy is actually delivered to PacifiCorp.

Q. WHAT IS PACIFICORP'S FOURTH ADJUSTMENT?

A. <u>QF Reliability</u>

PacifiCorp has defined an adjustment based on QFs' ability to operate reliably, considering such things as the unit's forced outage rate, its ability to meet the capacity that has been established (includes degradation), and performing maintenance according to the unit's schedule. PacifiCorp explains that this adjustment is actually subsumed within Adjustment 3. The Committee's comments to Adjustment 3 apply to this adjustment as well.

Q. WHAT IS PACIFICORP'S FIFTH ADJUSTMENT?

A. Accounting Standards Adjustments

B. Committee witness Kelly Francone addresses this adjustment in her testimony.

Q. WHAT IS PACIFICORP'S SIXTH ADJUSTMENT?

A. Wind Power Adjustments

PacifiCorp proposes several adjustments associated with wind power QFs. I will discuss some of these proposed adjustments and Ms. Francone addresses the adjustment pertaining to renewable energy credits (Green Tags).

PacifiCorp's first adjustment relates to imbalance costs and incremental operating reserve requirements caused by the intermittent nature of wind resources. According to PacifiCorp's IRP, "These additional costs are anticipated to occur in excess of that which would be due to an equivalent amount of energy delivered to the system on firm, fixed schedules."[1] It appears, therefore, that PacifiCorp is willing to pay a partial avoided capacity cost payment to wind power QFs, despite the fact that it treated wind power as non-firm capacity in its 2003IRP.

The Company is correct that wind generation is intermittent (non-firm) and should not be afforded the same treatment as firm QF resources. However, I believe that the value that wind resource offers to PacifiCorp can be captured through proper production cost modeling, using a differential revenue requirement approach to compute avoided costs. The wind power QF should be modeled as a non-firm resource, and the random output pattern of a wind resource should be simulated.

Q. HAS PACIFICORP CONDUCTED A STUDY TO ASCERTAIN THE IMPACTS OF WIND POWER ON ITS SYSTEM?

A. Yes. During the 2003 IRP, PacifiCorp conducted a study that is discussed in Appendix L of the IRP Report. In that study PacifiCorp determined the costs to integrate different levels of wind power capacity within its system. PacifiCorp concluded that the costs of integration vary greatly depending on the amount of wind power added. It determined that with 200 MW of wind power, imbalance costs will be less than 1$/MWh, but with 1,000 MW, the imbalance costs will be in the range of 3$/MWh – $3.25/MWh. Similarly, the costs of incremental reserve requirements were analyzed and PacifiCorp determined that those costs also vary with the amount of wind capacity added, ranging between $1.5/MWh and $2.7/MWh. For purposes of calculating avoided costs, the Company assumes 1,000 MW of wind power for determining integration costs. This results in an integration cost adjustment of $5.50/MWh for wind power QFs.

Q. PLEASE SUMMARIZE THE COMMITTEE'S RECOMMENDATIONS CONCERNING WIND POWER INTEGRATION COSTS.

A. The Committee's primary recommendation is that a differential production cost modeling approach should be relied on to calculate avoided costs, and as such, the specific characteristics of wind power resources should be captured in this modeling. If the Committee's recommendation is adopted by the Commission, no adjustment for wind power integration costs need to be made.

If PacifiCorp persuades the Commission that modeling wind power resources is too difficult, the Commission should not simply adopt the Company's proposed $5.50/MWh adjustment to determine integration costs. An adjustment should be made on the amount of wind power capacity <u>actually</u> on the System at the time a QF sells power to the Company. The integration cost penalty applied to as wind power QF can be calculated using the imbalance costs shown on page 367 of the 2003 IRP, and the incremental revenue requirement cost shown on page 369 of the 2003 IRP.

Q. ARE THERE ANY OTHER ISSUES OF CONCERN REGARDING PACIFICORP'S WIND POWER ADJUSTMENTS?

A. Yes, there is an issue related to Variable O&M (VO&M) costs that I noticed looking at PacifiCorp's example for modeling wind power projects. In Mr. Griswold's testimony, he explains that it is standard industry practice for wind purchases to be made on a purely volumetric pricing basis. To achieve this, PacifiCorp converts capacity costs measured in $/kW-yr to an equivalent cost measured in $/MWh. Then those costs

---

[1] PacifiCorp IRP Report, page 365, acknowledged by the Commission in May 2003.

are added to the avoided energy costs, and a single avoided cost stated in $/MWh is developed. However, a problem arises in the way PacifiCorp converts VO&M costs. PacifiCorp begins with VO&M costs stated in $/MWh, converts those costs to $/kw-year values, and then converts those back to $/MWh. This process can be observed by reviewing the workpapers supplied in response to the Committee's data requests 1.20, and 2.9. From data request 1.20, PacifiCorp supplied a file UT AC 2004 – AC Study w links.xls. On the worktab, Table 8, the first step in the conversion process can be observed. Variable O&M for a SCCT unit is specified as $9.67/MWh in 2004, and this is converted to a capacity value by the following conversion steps:

$9.67/MWh * 1 MW/1000 kW * (8760 hours/1 yr * .15) = $12.71/kw-yr

The unit 0.15 (15%) is the capacity factor assumption associated with a SCCT unit. This equivalence means that as long as the SCCT operates for .15 * 8760 hours, or 1314 hours, then VO&M cost of $9.67/MWh will yield exactly the same result as the VO&M costs stated as $12.71/kW-yr. PacifiCorp's response to DR 2.9 shows how PacifiCorp converts the avoided costs to be stated entirely in terms of $/MWh. The VO&M costs that had been converted to $12.71/kw-yr is now converted back to $/MWh terms, but this time using the assumption of 100% capacity factor.[2]

$12.71/kw-yr * 1yr/(8760 hours * 1.0) *1000 kW/1MW = $1.45/MWh

Thus, the VO&M costs which began as $9.67/MWh is first converted to a $/kw-yr value using a 15% capacity factor assumption, and then it is converted back to a $/MWh value using a 100% capacity factor assumption. The resulting VO&M costs ends up as only $1.45/MWh, which is 85% below what it started out at in the beginning. This makes little sense and should be corrected.

Q. WHAT ARE THE COMMITTEE'S RECOMMENDATIONS CONCERNING THIS CONVERSION CALCUATION?

A. First, PacifiCorp should be required to correct this error. Secondly, it should also be required to confirm to the Commission that it has checked to see if any other conversion errors of this nature exist. There may be other places in the calculation process that PacifiCorp converts values back and forth, and the Company should check for conversion errors and correct such errors if they exist.

Q. DOES PACIFICORP HAVE A SEVENTH AND FINAL ADJUSTMENT?

A. Yes. In his testimony, Mr. Griswold notes that PURPA distinguishes between facilities built pre and post 9 November 1978 when PURPA regulations were first implemented. According to Mr. Griswold, PacifiCorp desires to offer lower avoided cost payments to QFs that were built prior to 9 November 1978, as long as the Commission finds that the rates proposed are just and reasonable, and adequate to encourage cogeneration and small power production. However, he did not recommend an approach to make an adjustment.

Q. WHAT IS THE COMMITTEE'S RECOMMENDATION ON PACIFICORP'S DESIRE TO HAVE A PRE-PURPA QF ADJUSTMENT?

A. The Committee takes no position on this matter at this time. The Committee believes that as part of this proceeding PacifiCorp should either develop a pre-PURPA methodology for calculating an adjustment that parties can review methodology or drop the issue.

IV. COMMITTEE'S ADDITIONAL SCHEDULE 37 RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. PacifiCorp's standard avoided cost calculation is identical in both the Company's Schedule 37 and 38 filings, therefore, some of the Committee's recommendations are applicable to both schedules. This section discusses recommendations the Committee has already made to the Commission in its memo on Schedule 37, dated 9 April 2004.

Q. PLEASE EXPLAIN THE DIFFERENCES IN THE COMMITTEE'S POSITION BETWEEN SCHEDULE 37 AND 38.

A. Because Schedule 37 applies to QFs up to 1 MW in size, the Committee understands that the Company may prefer to have a streamlined process for

---

[2] PacifiCorp's avoided cost approach actually treats VO&M as a capacity cost in $/kw-yr.

developing avoided costs based on the assumption of a constant 10 MW QF. Thus, the Committee did not object to the Company's proposal for a two-phased approach: a differential revenue requirement methodology for the resource sufficiency period; and a proxy methodology for the resource deficiency period.

However, for purposes of calculating avoided costs for QFs greater than 1 MW in size, the potential avoided costs to be paid by ratepayers to QFs are significantly higher. For instance, PacifiCorp's witness Mark Tallman testified that in 2003 actual QF power purchase costs amounted to $75 million dollars. In (DPU DR 1.14), Mr. Tallman indicates that there are potentially 393 MW available from Utah QFs, which could amount to hundreds of millions of dollars of avoided cost payments. That is why the Committee strongly recommends that the Commission adopt more precise methodologies for determining avoided energy and capacity costs.

Q. PLEASE LIST THE COMMITTEE'S RECOMMENDATIONS THAT ARE COMMON TO BOTH SCHEDULES.

A. A summary list of recommendations from the Committee's Schedule 37 memo is provided below. I have also attached the memo as CCS Exhibit 2.2.

The Committee recommends the Commission limit the definition of the summer period to June through September. PacifiCorp has defined this seasonal period as May through October, which distorts the true summer and winter periods, as well as the corresponding avoided costs. (Recommendation 2.1 in 9 April 2004 memo)

The Committee recommends the Commission expand the minimum number of months in which the avoided cost capacity payments should be made from three months to six months. The three months recommended by PacifiCorp does not comport with the number of months it is capacity deficient and thus requires additional capacity resources. (Recommendation 2.2 in 9 April 2004 memo)

In determining the variable and fixed O&M costs assumed for a Simple Cycle Combustion Turbine (SCCT), PacifiCorp made an error, which the Committee has corrected, and recommends the adoption of. (Recommendation 2.3 in 9 April 2004 memo)

The Committee recommends that the Commission adopt a more accurate averaging calculation for annual average avoided costs. PacifiCorp's methodology distorts the average, which impacts the avoided costs. (Recommendation 2.4 in 9 April 2004 memo)

Due to the volatility of natural gas prices and the subsequent impact on the avoided costs, the Committee provides two options relating to natural gas prices: 1) if the Commission prefers a fixed price forecast, we recommend the Commission adopt the Committee's alternative gas price forecast that is based on PacifiCorp's forecast and those provided by NYMEX and the Energy Information Administration (EIA); or 2), if the Commission prefers relying on actual gas prices to reflect more accurate fuel costs, the Committee recommends the Commission tie the cost to the index fuel price and set rates at the time the power is delivered. (Recommendation 2.5 in 9 April 2004 memo)

Q. PLEASE PROVIDE A COMPARISON OF YOUR AVOIDED COSTS TO PACIFICORP'S FOR SCHEDULE 38.

A. At this time, I can only provide a table (Table 1) containing avoided cost results for 2004 through 2006, as PacifiCorp has not developed its GRID database beyond 2008. This analysis assumes that a 10 MW QF has presented itself to PacifiCorp**.**

Table 1
Comparison of Schedule 38 Avoided Costs
PacifiCorp versus Committee Assuming a 10 MW QF

Year	PacifiCorp's Proposed Avoided Costs filed in Jan 2004 ($/MWH)	Committee's Modifications to PacifiCorp's Jan 2004 Avoided Cost Filing ($/MWH)
2004	$33.36	$36.22
2005	$44.07	$46.99

2006	$41.89	$44.90

Q. PLEASE SUMMARIZE THE REASON FOR THE DIFFERENCES IN RESULTS.

A. The difference in results is driven by two factors. First, the Committee's gas price forecast is higher than PacifiCorp's, as discussed in the Committee's Schedule 37 Memo attached as CCS Exhibit 2.2. Second, the Company assumed that during the sufficiency period, loads and resources were out of balance for only the three summer months. Upon closer inspection, it appears that this imbalance condition occurs on average for as many as six months per year, and the Committee calculated avoided capacity payments with this assumption.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.