Witness CCS – 1

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**:**	
PacifiCorp for Approval of an IRP-based	**:**	**Docket No. 03-035-14**
Avoided Cost Methodology for QF	**:**	
Projects Larger than Three Megawatts	**:**	
	:	

DIRECT TESTIMONY OF

PHILIP HAYET

ON BEHALF OF
THE COMMITTEE OF CONSUMER SERVICES

July 29, 2005

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Philip Hayet, and I am President of Hayet Power Systems Consulting ("HPSC"), 215 Huntcliff Terrace, Atlanta, GA 30350.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an electric utility industry consultant and I am testifying on behalf of the Utah Committee of Consumer Services ("Committee").

Q. WHAT CONSULTING SERVICES DOES HPSC PROVIDE?

A. HPSC provides consulting services related to electric utility system planning, load forecasting, resource analysis, production cost modeling, and utility industry policy analysis.

Q. PLEASE SUMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in CCS Exhibit No. 1.1 attached to my testimony.

SUMMARY AND RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. PacifiCorp has filed an application for approval of a Differential Revenue Requirement ("DRR") avoided cost method for qualifying facility ("QF") projects between three and 99 megawatts ("MWs") in size. I present the Committee's analysis and recommendations on the reasonableness of PacifiCorp's proposed DRR method and I address other avoided cost issues raised in the Company's testimony.

Q. WHICH OF THE COMPANY'S WITNESSES' TESTIMONY DO YOU ADDRESS?

A. I address issues that were introduced by Mr. Gregory Duvall and Mr. Bruce Griswold. Mr. Duvall, Managing Director, Planning Major Projects, describes the Company's proposed avoided cost method for QFs from 3 to 99 MWs. Mr. Griswold, a Manager in the Origination section of the Company's Commercial and Trading Department, discusses:

- adjustments to calculated avoided costs for QF contracts between 3 and 99 MW;
- the Company's proposal for purchases from QF's that are 100 MW or larger; and
- renewable QF Issues.

Q. DOES THE COMMITTEE BELIEVE THAT THE COMPANY'S PROPOSED DRR AVOIDED COST METHOD IS REASONABLE?

A. The Committee believes that the use of a DRR method is reasonable. However, we have identified problems with PacifiCorp's implementation of the DRR method, which will be discussed further in this testimony.

Q. PLEASE SUMMARIZE THE COMMITTEE'S RECOMMENDATIONS.

A. <u>General Avoided Cost Recommendations</u>

- **DRR Recommendation** – The DRR approach is reasonable and should be adopted for calculating avoided costs for QFs between 3 and 99 MW.
- **Revised DRR Method** - The Company's DRR approach should be revised consistent with the Committee's recommendations that will be discussed below.
- **Avoided Cost Adjustments** – The Company discusses a general set of adjustments that apply to all QFs, as well as additional adjustments that are specific to renewable QFs. The Committee

agrees with all of the Company's proposed general adjustments. However, in the case of one adjustment, QF Reliability, the Committee would like the Company to provide additional details on how QF reliability will be determined and how the adjustment will be made. The Company's specific renewable adjustments are discussed separately in my testimony.

- **QFs 100 MWs and Greater** - The Committee agrees with the Company that QFs greater than 100 MW should be required to participate in a competitive bidding process.

Renewable QF Recommendations

- **Renewable Energy Credits** – The Committee recommends that renewable QFs should be permitted to retain the Renewable Energy Credits (REC) associated with the energy they generate.
- **Wind Energy Capacity Payments** – The Company proposes that if a wind QF generates at a 35% annual on-peak capacity factor, then the QF should be entitled to receive a 20% capacity payment. The Committee generally agrees with the logic associated with this proposal; however, if a wind QF generates at a 35% annual on-peak capacity factor, then the Commission may want to consider allowing a capacity payment in the range of 20% – 30%.
- **Wind Integration Costs** – The Committee believes that wind integration costs are legitimate and that $4.64/MWh is a reasonable estimate of integration costs. However, the Committee is attempting to determine if integration costs can be more properly estimated in the production cost modeling (GRID model). The Committee will provide its integration cost recommendation in its rebuttal testimony.

STANDARD DRR AVOIDED COST METHOD

Q. PLEASE PROVIDE AN OVERVIEW OF THE DRR METHOD.

A. The DRR method has been around since the passage of PURPA legislation in 1979, and has been widely used by utilities to compute avoided energy costs. The DRR method requires the use of production cost modeling to simulate the operation of the utility system and to forecast energy production costs over a future period. In the case of avoided energy costs, the utility is typically interested in a 20-year forecast period.

The DRR method requires two production cost runs to be made. The first run reflects the way the utility would operate its system without the QF; the second run reflects the way the utility would operate its system if the QF energy were available at zero cost.

Q. HOW ARE AVOIDED ENERGY COSTS COMPUTED BASED ON THESE TWO RUNS?

A. The difference in production costs between the two runs represents the energy benefit that a zero cost QF would provide to the utility system. If the QF were paid an amount equal to the production cost savings between the two runs, then the utility's total production costs to serve its load requirement would be identical whether it generated the energy without or with the QF. Avoided energy costs (measured in $/MWh) are computed by dividing the difference in production costs in the two runs by the QF energy sold to the utility.

Q. HOW ARE AVOIDED CAPACITY COSTS COMPUTED?

A. There are a number of ways that avoided capacity costs can be computed consistent with the DRR approach. The most theoretically correct way is to develop two optimal resource plans, with and without the QF. The difference in annual capital revenue requirements between the two cases divided by the capacity of the QF resource is the avoided capacity cost (measured in $/kW-yr).

Q. ARE THERE OTHER APPROACHES THAT ARE USED TO COMPUTE AVOIDED CAPACITY COSTS?

A. Yes. A utility may find it difficult to develop multiple optimal resource plans for the cases with and without the QF. Another approach is to assume that the capacity cost of the next resource that the utility will construct is the utility's avoided capacity cost. This is commonly referred to as the Proxy Method.

PACIFICORP'S VARIATION OF THE DRR METHOD

Q. IS PACIFICORP'S PROPOSED DRR METHOD CONSISTENT WITH THE STANDARD DRR MODELING APPROACH?

A. PacifiCorp computed avoided energy costs using a variation of the DRR method described above. It computed avoided capacity costs based on the Proxy Method mentioned above. Thus, its avoided capacity costs will be based on the cost of the next resource that will be constructed, which is a 525 MW Combined Cycle Combustion Turbine ("CCCT") unit expected to be online in 2009.

Q. PLEASE EXPLAIN THE COMPANY'S VARIATION OF THE DRR METHOD FOR CALCULATING AVOIDED ENERGY COSTS?

A. The Company assumes that between now and when its next IRP resource is scheduled to come online in 2009, 525 MW of new QF resources from 3 to 99 MW in size will be installed. PacifiCorp believes that the addition of these new QFs will completely supplant the 2009 IRP resource. For modeling purposes, PacifiCorp removes the IRP resource from the second production cost run, and replaces it with QF resources. In fact, two QF resources are added. The first is what I will refer to as an “adjustable” QF resource, and the second is the QF resource requesting indicative prices. The capacity of the adjustable resource starts at 525 MW, but is modified depending on the size of the QF applying for indicative prices. For example if a 99 MW QF applies for indicative prices, then the adjustable resource becomes a 426 MW resource (525 MW – 99 MW = 426 MW). The intent is to always include a 525 MW block of QF capacity in the second run. The fact that the Company models two QFs, one based on the characteristics of the QF requesting indicative prices, and the other an adjustable QF resource is a variation to the standard DRR approach.

Q. HOW DOES THE COMPANY COMPUTE AVOIDED COSTS BASED ON THIS APPROACH?

A. PacifiCorp runs its GRID production cost model twice. The first run is the base case with no QFs, but it contains the Company’s latest IRP resource plan assumptions (including the 2009 IRP resource). The second run includes three changes to the base case; it contains a zero cost resource having the characteristics of the QF in question; it includes an adjustable QF resource that is modeled as a base loaded resource; and it removes the 2009 IRP resource. The difference in production costs between the two runs divided by the total QF energy is the avoided energy cost.

Q. IN ADDITION TO ADDING THE QF RESOURCE OF INTEREST, WHY DOES PACIFICORP ALSO PROPOSE TO ADD AN ADJUSTABLE,

BASE LOAD (100% CAPACITY FACTOR) QF RESOURCE AND COMPLETELY REMOVE THE IRP RESOURCE IN THE SECOND RUN?

A. Mr. Duvall explained in his testimony this was done so that the Company could maintain consistency between the avoided capacity and avoided energy cost calculations. The Company reasoned that if QF resources are to receive an avoided capacity payment based on the fixed costs of PacifiCorp's 2009 IRP CCCT resource, then QF resources would have to completely replace the 2009 IRP resource in the second run of the avoided energy cost calculation. With the removal of the 525 MW IRP resource, and the addition of a QF resource between 3 and 99 MW in size, PacifiCorp realized that the change case would have a shortage of capacity compared to the base case, unless an additional resource were added. PacifiCorp's solution was to add an adjustable QF resource, such that the sum of the capacity of the adjustable QF resource and the QF resource of interest would sum to 525 MW. Mr. Duvall concluded that with these assumptions the resource plan in the cases with and without the QF resources would be consistent.

Q. HOW WOULD PACIFICORP COMPUTE INDICATIVE COSTS FOR ANOTHER QF THAT MIGHT COME ALONG AT A LATER TIME; FOR EXAMPLE, A 20 MW QF THAT COMES ALONG SIX MONTHS AFTER THE FIRST?

A. For the 20 MW QF, the second production cost run from the previous case would become the new base case. In other words, the base case for the 20 MW QF would be set up such that:

- The 525 MW IRP resource would be removed;
- The 99 MW QF resource from the previous case would be included in the new base case; and
- The 426 MW adjustable QF from the previous case would be included in the new base case.

In the second run, the 20 MW QF would be added and the 426 MW adjustable QF resource would be reduced to a 406 MW resource (426 MW – 20 MW = 406 MW).

Q. DO YOU BELIEVE THAT PACIFICORP'S DRR VARIATION METHOD USING AN ADJUSTABLE QF RESOURCE IS REASONABLE?

A. No I don't. PacifiCorp's base case, which reflects the Company's IRP resource plan, is not equivalent to another case in which one of the IRP resources is removed and replaced with an adjustable base loaded QF resource and the QF project of interest. For example, if a 99 MW dispatchable QF were to approach PacifiCorp for indicative pricing, then the IRP resource would be removed and replaced with the 99 MW QF and a 426 MW QF.

In a separate analysis that I conducted for the year 2010 to evaluate the avoided cost results of a 99 MW QF, I found that the avoided energy cost results were dominated by the 426 MW adjustable capacity resource that had been added.

In the base case of my analysis the 2009 CCCT IRP resource generated with an annual capacity factor of 36.6% and produced 1,681 GWh of energy. In the change case, with the CCCT IRP resource having been removed, the 426 MW base loaded QF operated with a 100% capacity factor and produced 3,732 GWh of energy, and the 99 MW dispatchable QF resource operated with a 51% annual capacity factor and produced 445 GWh of energy.

Q. WHY DID THE 426 MW QF DOMINATE THE RESULTS?

A. Normally, the goal of a DRR analysis is to determine the cost of the energy that would be avoided by the QF project of interest. PacifiCorp's DRR method does not do this. In the analysis that I conducted using PacifiCorp's DRR method, the 426 MW adjustable played a more significant role in determining the avoided costs than the 99 MW QF project that had applied for indicative pricing. Since the 99 MW QF was a dispatchable resource (modeled similar to one of PacifiCorp's existing CCCT units), it should have displaced gas-fired generating units or market purchases from Palo Verde or Four Corners. However, PacifiCorp's DRR method also adds the 426 MW base loaded QF resource which results in other cheaper resources being avoided. My analysis shows coal-fired units were displaced by the 426 MW resource during certain hours. Thus, the avoided cost results were dominated by the larger QF resource.[1]

[1] As noted above, the 99 MW OF produced 445 GWh of energy, while the 426 MW QF produced 3,732 GWh of energy, which is 8 times more energy than produced by the 99MW QF.

Q. CAN YOU RECOMMEND ANY REVISIONS TO THE COMPANY'S DRR METHOD?

A. Yes, the Committee recommends that the adjustable QF resource logic should be eliminated and the avoided energy costs should be computed using the standard DRR method. In other words, avoided energy costs should be computed as the difference in production costs between a base case without the QF and a change case with the QF set at zero cost. The avoided energy cost rate ($/MWh) would be determined by dividing the production cost difference by the QF energy.

Q. HAVE YOU COMPUTED AVOIDED COSTS BASED ON YOUR METHOD?

A. Yes, I developed avoided costs for a 99 MW QF that offers to sell capacity and energy to PacifiCorp on a firm basis during all of the on-peak and off-peak hours.

Q. HOW DO YOUR AVOIDED COST RESULTS COMPARE TO PACIFICORP'S RESULTS?

A. As shown in CCS Exhibit No. 1.2, the Committee's avoided cost result is $49.27/MWh on a 20-year levelized basis beginning in calendar year

2006.[2] The Committee's $49.27/MWh is somewhat higher than the Company's $46.62/MWh.[3]

Q. MR. DUVALL MENTIONS IN HIS TESTIMONY THAT AVOIDED ENERGY PRICES SHOULD BE CAPPED AT THE FUEL COST OF A CCCT UNIT. HAVE YOU INCLUDED THIS LIMIT IN YOUR ANALYSIS?

A. Yes, I have. The Committee agrees with PacifiCorp that its avoided energy costs at any time should not exceed the fuel cost of a CCCT unit.

Q. ARE THERE ANY OTHER ANALYSES THAT YOU WOULD STILL LIKE TO PERFORM?

A. Yes. I would like to examine the case of a QF that requests indicative pricing and is a fully dispatchable resource such as Desert Power. Should the results of this analysis comply with PURPA, I will present it in my rebuttal testimony.

Q. HOW DO YOU RESPOND TO PACIFICORP'S CONCERN THAT IF IT PAYS AN AVOIDED COST CAPACITY PAYMENT BASED ON AN IRP RESOURCE, IT WANTS TO FULLY REMOVE THAT RESOURCE WHEN IT PERFORMS ITS AVOIDED COST ENERGY MODELING?

A. While this is a reasonable concern, completely removing a 525 MW dispatchable CCCT IRP resource from the example discussed above that

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[2] The Committee's results included a 99 MW QF that is assumed to sell power to PacifiCorp in all hours. Should the QF operate differently, then the specific operating characteristics would have to be modeled in the second run.

[3] PacifiCorp's updated avoided costs were provided to the parties in a letter distributed on May 27, 2005. These results were only slightly different than what were included in Mr. Duvall's Testimony Exhibit GND-1.

generated 1,681 GWh and replacing it with a 426 MW unit that produced 3,732 GWh is not an appropriate solution. Furthermore, the Company can not even be certain that it will acquire enough QF capacity such that it would be able to eliminate an entire IRP resource. Mr. Duvall acknowledges this on page 3 of his testimony in the following Q & A.

> ***Q. Can you be certain that the Company will acquire enough QF power to avoid adding the 2009 CCCT?***
>
> *A. No. There is a risk that not enough QF power will be acquired to avoid the 2009 CCCT. However, if the 2009 CCCT is avoided, customers will be neutral. Unfortunately, there is no way to predict how much QF power the Company will acquire under its proposed avoided cost rates.*

Q. BASED ON THE DRR APPROACH THAT YOU HAVE PROPOSED, CAN YOU SUGGEST A WAY TO ADDRESS THE COMPANY'S CONCERN?

A. As I discussed earlier, the most theoretically correct way to create the resource plans for both the base case and change case would be to develop optimal resource plans following the process developed in the IRP study. Since this requires a significant amount of effort, I have proposed to simply rely on the same IRP resource plan in both the base and the change cases. However, there is one more adjustment that I could suggest, which will require further examination. In the second run, instead of completely removing the IRP resource and replacing it with an adjustable capacity QF resource, along with the QF resource of interest, the QF resource of interest could be added and then the IRP resource could be scaled back by the amount of capacity of the QF project. For instance, if a 99 MW QF is added in the second run, then the 2009 IRP resource could be reduced in size by 99 MW for modeling purposes. The Committee will examine this modeling alternative and may present additional results in its rebuttal testimony.

<u>PACIFICORP'S PROPOSED AVOIDED COST ADJUSTMENTS</u>

Q. WHAT IS THE PURPOSE OF PACIFICORP'S PROPOSED AVOIDED COST ADJUSTMENTS?

A. PacifiCorp is only obligated to pay a QF what it would cost to generate or purchase the same amount and type of capacity and energy. When a QF cannot provide the same quality of capacity and energy compared to what PacifiCorp could produce or acquire, then certain adjustments should be made to the QF capacity and energy payments. This ensures that customers would be economically indifferent to who provided the capacity and energy to meet PacifiCorp's load requirements.

Q. PLEASE LIST PACIFICORP'S PROPOSED ADJUSTMENTS AND STATE WHETHER THE COMMITTEE AGREES WITH EACH PROPOSED ADJUSTMENT.

A. PacifiCorp witness Griswold proposes the following avoided cost adjustments:

- <u>Firm vs. Non-Firm Power</u> – QFs that supply non-firm power will not be entitled to a capacity payment. Those QFs will only be entitled to an energy payment. The Committee agrees with this adjustment.

- Operating Reserve Treatment – QFs that do not provide operating reserves will receive lower avoided energy cost payments. The proposed DRR method will specifically reflect whether or not a QF can provide operating reserves; therefore, the avoided energy costs will be lower for those QFs that cannot provide operating reserves. The Committee agrees with this adjustment.
- Dispatchability – QFs that are non-dispatchable will receive lower avoided energy cost compared to QFs that are dispatchable. Again, the Company's production cost modeling will directly capture this effect. The Committee agrees with this adjustment.
- QF Reliability – Mr. Griswold indicated that heat rate and capacity degradation of a QF might lead to an adjustment to the capacity payment. The Committee agrees conceptually that when a QF is less reliable than expected, an adjustment should be made. However, the Committee would like the Company to provide additional information about how QF reliability will be determined and the basis for any adjustment.

QFS 100 MWS OR GREATER

Q. HOW DOES PACIFICORP PROPOSE TO TREAT QFS THAT ARE 100 MW OR GREATER IN SIZE AND WHOSE CONTRACT TERMS ARE TEN YEARS OR LONGER?

A. PacifiCorp proposes that all QFs 100 MW or greater and that have contract terms of ten years or longer be required to go through the

Company's competitive bidding process in order to receive capacity payments. The Company believes that these large QFs should be treated in a consistent manner with other large generators that want to sell power to the Company. The competitive bidding process was adopted in the Energy Resource Procurement Act, U.C.A. §54-17-101 et seq., (the "Act") as a way to encourage the acquisition of the most cost-effective resources from the market.

Q. IF A QF WAS NOT SELECTED AS THE WINNING BIDDER IN THE COMPETITIVE BIDDING PROCESS, COULD IT STILL RECEIVE AVOIDED COST PRICING?

A. PacifiCorp proposes that any QF that was not the winning bidder would only be eligible to receive avoided energy payments based on the DRR method.

Q. DOES THE COMMITTEE AGREE WITH PACIFICORP'S PROPOSAL FOR QFS THAT ARE 100 MW OR GREATER IN SIZE?

Yes. A market-based approach will ensure that PacifiCorp does not overpay for large QF resources.[4]

The competitive bidding process is intended to be linked to PacifiCorp's IRP process. Once the optimal resources are identified in the IRP process, the competitive bidding process will ostensibly allow PacifiCorp to acquire those resources at the lowest cost. If large QFs were permitted

[4] This is particularly important in the context of the MSP cost allocation process in which any state that enters into QF contracts that have avoided costs that exceed market will be directly assigned the portion of avoided costs that are above market.

to arrange for QF contracts outside of the competitive bidding process there would be little assurance that PacifiCorp would be able to acquire the most economic resources as set forth in the IRP.

<u>RENEWABLE QF ISSUES</u>

Q. WHY DOES MR. GRISWOLD IDENTIFY SPECIFIC ADJUSTMENTS RELATED STRICTLY TO RENEWABLE QF PROJECTS?

A. Over the last few years, renewables have become preferred resources by many utilities as they allow the utility to either fulfill state mandated Renewable Portfolio Standards ("RPS"), or they allow the utility to satisfy requirements established by Green Pricing Programs. Although Utah does not currently have a RPS requirement, several western states do have one and PacifiCorp does have a Green Pricing Program. In the future the Utah legislature may once again consider enacting a RPS.

Many of the RPS and Green Pricing Programs allow utilities to buy Renewable Energy Credits ("RECs") or "Green Tags" from other companies that own the rights to renewables and have the attributes that are required to satisfy the programs. In the case of renewable QFs, the issue of REC ownership arises in the context of purchasing capacity and energy from renewable QF suppliers. Additional issues arise in the case of wind resources, because wind is an intermittent energy source that cannot be fully counted on for capacity in terms of long-term resource planning, and wind resources place additional requirements on the utility during the short-term operation of the system.

Q. WHAT ARE THE DIFFERENT POINTS OF VIEW REGARDING GREEN TAG OWNERSHIP?

A. PacifiCorp believes that when it buys power from QFs, it should also receive the Green Tag without having to make any further payment to the QF. PacifiCorp asserts the environmentally friendly aspect of a renewable QF is precisely the attribute that allows the renewable QF to sell power to PacifiCorp under PURPA. Because Green Tags are an inherent part of a renewable QF, and since the QF has the right to put power to the utility, PacifiCorp argues it should be entitled to the Green Tag at zero cost when it pays the QF for capacity and energy. Conversely, renewable QFs would most likely be unwilling to transfer ownership of the Green Tags to PacifiCorp absent a reasonable level of compensation.

Q. MR. GRISWOLD REFERS TO THE FACT THAT FERC HAS ADDRESSED THIS ISSUE TO SOME EXTENT. WHAT IS HIS IMPRESSION OF FERC'S OPINION ON THE OWNERSHIP ISSUE?

A. On page 9 of Mr. Griswold's testimony, he explains that FERC issued an Order in late 2003 stating that determination of the control and ownership of QF Green Tags should be made by each individual state. To put this in context, it is helpful to see FERC's own explanation. In its Order Denying Rehearing issued April 15, 2004, in Docket EL03-133-001[5], FERC referred to and commented about its original Order in that same docket in the following way,

> *"…contracts for the sale of qualifying facility (QF) capacity and energy entered into pursuant to PURPA do not convey renewable energy credits or similar tradeable certificates (RECs) to the purchasing utility (absent express provision in a contract to the contrary). The Commission further declared that while a State may decide that a sale of power at wholesale automatically transfers ownership of the State-created RECs, that requirement must find its authority in State law, not PURPA."*

While FERC acknowledged that States have the right to decide the ownership question, FERC also declared that QFs had ownership rights to the RECs for contracts executed prior to RECs being a contestable issue.[6] In making this determination, FERC essentially decided that QFs had rights to the additional attributes associated with the QF energy and those rights could only be transferred to the utility based on mutually acceptable terms between the parties.

Q. WHAT IS THE COMMITTEE'S POSITION ON GREEN TAG OWNERSHIP?

A. It is generally accepted that Green Tags have economic value in the marketplace, and since the QF is the owner of the resource, it is the legitimate owner of the Green Tag. The Committee believes that it would be unfair to transfer the ownership rights of Green Tags to the utility for free. If a utility wants to pay to acquire the Green Tags, then it should have the first right to be able to buy them from the QF. This should be

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[5] American Ref-Fuel Company, et al., 105 FERC ¶ 61,004 (2003) (October 1 Order).
[6]Absent express provision in a contract to the contrary.

negotiated as a part of the QF contract, and if no agreement can be reached, then the Green Tags should remain with the renewable QF.

Q. YOU MENTIONED THERE ARE TWO OTHER ISSUES ASSOCIATED WITH WIND QFS ADDRESSED BY PACIFICORP. PLEASE DISCUSS THOSE ISSUES.

A. The two issues relate to how wind resources impact a utility's long-term resource plan, and short-term operation of its system. Concerning the issue of long-term resource planning, the amount of wind capacity that will be available in the future will depend on wind speed and duration. Compared to conventional thermal resources, there is greater uncertainty as to whether wind resources will be available to serve a utility's peak load requirements. This uncertainty leads utilities to discount the capacity value of wind resources when conducting resource planning studies.

Q. HOW HAS PACIFICORP TREATED WIND RESOURCES IN ITS TWO RECENT IRP STUDIES?

A. In its 2003 IRP, PacifiCorp assumed that wind provided no capacity value whatsoever, which meant that no matter how many megawatts of wind capacity it added to its resource plan, none of those megawatts were able to count towards its reserve margin requirement. In its 2004 IRP, PacifiCorp conducted a reliability study and determined that for every 100 MW of wind resources that could be added to its system, the reliability benefit of the wind resources was equivalent to adding 20 MW of conventional thermal capacity. For long-term resource planning purposes, PacifiCorp settled on assigning wind resources a 20% capacity credit. Regarding its proposed avoided cost method, PacifiCorp also recommends that this 20% capacity credit be applied to wind QFs.

Q. DOES THE COMMITTEE BELIEVE THAT A 20% CAPACITY CREDIT IS REASONABLE FOR WIND RESOURCES?

A. The appropriate capacity credit level is difficult to determine. The answer depends on the reliability benefit that wind resources provide to the utility system and this can only be ascertained by performing a detailed reliability study. System reliability varies depending on the utility system being examined and one cannot necessarily point to reliability studies conducted for other utility systems to suggest that the results will be the same for PacifiCorp's system.

Q. HAVE YOU REVIEWED STUDIES THAT SUGGEST THAT THERE IS A WIDE VARIATION IN THE CAPACITY CREDIT VALUE ASSOCIATED WITH WIND RESOURCES?

A. I have reviewed some studies. For example, Xcel Energy conducted a reliability study that examined the impacts of wind resources on its Minnesota service territory.[7] The reliability study was conducted using General Electric’s reliability model, GE MARS (Multi-Area Reliability Simulation). The results showed that the capacity value of the wind resources ranged from 26.67% when 400 MW of wind resources were

[7] XCEL Energy and the Minnesota Department of Commerce, Wind Integration Study – Final Report, Prepared by EnerNex Corporation, September 28, 2004, http://www.uwig.org/XcelMNDOCStudyReport.pdf

added to 33.75% when 1500 MW of wind resources were added.[8] In another study conducted by GE for New York using its MARS software, GE determined that the capacity value of inland wind power sites in New York have about a 10% capacity value, even though their energy capacity factors are on the order of 30%.[9] Part of the reason for this lower capacity value had to do with the location of the wind resources on the transmission system, relative to transmission congestion and the location of New York's major load centers.

Q. HAS PACIFICORP CONDUCTED AN EVALUATION OF THE RELIABILITY BENEFIT OF WIND ON ITS SYSTEM?

A. PacifiCorp conducted its own reliability study as part of its 2004 IRP and the results are described on pages 139 – 144 of its IRP Technical Appendix. The Company followed a method developed by the National Renewable Energy Laboratory ("NREL") and Xcel Energy, which was described in a study that was performed to evaluate the reliability benefit of wind located in Xcel's Colorado Service Territory. PacifiCorp does not discuss which model it used to conduct its reliability analysis, but it is unlikely that it conducted the same detailed reliability modeling as conducted by GE using its MARS software. Based on its analysis,

[8] Page 66 XCEL Energy Wind Integration Study

[9] The Effects Of Integrating Wind Power On Transmission System Planning, Reliability, And Operations Report On Phase 2: System Performance Evaluation, Prepared For: The New York State Energy Research And Development Authority, Albany, NY, GE Energy, March 4, 2005, http://www.nyserda.org/publications/wind_integration_report.pdf

PacifiCorp concluded that wind resources on its system provide a 20% capacity value when compared to conventional thermal resources.

Q. WHAT IS THE COMMITTEE'S RECOMMENDATION FOR THE WIND POWER CAPACITY CREDIT?

A. The Committee is confident that there is at least a 20% capacity equivalence between wind resources and thermal resources for wind projects that are located in Utah. We also recognize that other reliability studies demonstrate a higher capacity credit value could be justified as additional wind resources are added to a utility system. Therefore, the Commission may want to consider establishing a capacity value between 20% and 30%.

Q. DOES PACIFICORP PROPOSE A MINIMUM CAPACITY FACTOR REQUIREMENT FOR WIND RESOURCES TO BE ABLE TO RECEIVE THE AVOIDED CAPACITY PAYMENT?

A. Yes, PacifiCorp proposes a minimum capacity factor requirement of 35%. In other words, a wind resource must operate with a 35% annual on-peak capacity factor in order to be eligible to receive a 20% capacity credit payment. A 35% capacity factor was selected as a reasonable estimate of the annual on-peak capacity factor of a typical wind resource. The Company believes, for example, that 100 MW of wind resources operating with a 35% annual on-peak capacity factor will provide the equivalent reliability benefit as 20 MW of thermal generation resources operating with capacity factors that are typical for those units. On page 11 of his testimony, Mr. Griswold notes that wind capacity factors of 25% to 40% are common throughout the wind industry.

Q. WHAT IS THE COMMITTEE'S POSITION REGARDING THE 35% CAPACITY FACTOR REQUIREMENT?

A. The Committee agrees that an annual on-peak capacity factor of 35% is reasonable and should be the minimum capacity factor requirement for wind resources to be able to receive an avoided capacity cost payment. But as discussed above the Commission may want to consider setting the capacity payment level between 20% and 30%.

Q. YOU PREVIOUSLY MENTIONED THAT WIND RESOURCES PLACE ADDITIONAL REQUIREMENTS ON THE UTILITY DURING SHORT-TERM OPERATION OF THE SYSTEM. DOES PACIFICORP ACCOUNT FOR THIS WITH AN ADDITIONAL ADJUSTMENT?

A. Yes, PacifiCorp proposes an Integration Cost adjustment that reflects the additional costs to operate PacifiCorp's system on a short-term basis given that wind energy production depends on wind speed and duration. Loss of wind production would have to be immediately replaced by other capacity that would be maintained in a state of readiness. PacifiCorp proposes to reduce its avoided energy cost payments to wind QFs to reflect the additional costs that PacifiCorp will incur to integrate energy received from wind QFs. PacifiCorp has conducted a study showing that it will cost $4.64/MWh to integrate wind energy on its system. Most of this added expense relates to additional operating reserves that are required when wind resources supply part of the system's load requirement.

Q. IS THE COMMMITTEE CONVINCED THAT WIND RESOURCES LEAD TO UTILITIES INCURRING ADDITIONAL INTEGRATION COSTS?

A. Yes. There is little argument in the industry that wind resources do result in the utility incurring additional integration costs. The more important question is how significant are the integration costs. Some experts argue that the impacts are small when the amount of wind energy is small relative to the size of the utility system, but the impacts become more significant as the amount of wind resources increase on the system. This is a subject of significant debate in the wind energy community. However, a number of sources cite studies that point to $5/MWh as a reasonable estimate for wind integration costs. As two examples, Bonneville Power offers a wind integration product that is priced about $5/MWh[10], and Northwestern Energy in its application for its power purchase agreement for its Judith Gap wind power resource also concludes that 5$/MWh is a reasonable price for wind integration costs.[11]

Q. DOES THE COMMITTEE RECOMMEND USING $4.64/MWH AS AN ADJUSTMENT TO AVOIDED ENERGY COSTS DUE TO WIND ENERGY INTEGRATION COSTS?

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[10] See press release at http://www.bluefish.org/mixwind.htm

[11] Public Service Commission State of Montana, Docket D2005.2.14, Service Date: March 31, 2005, Final Order No. 6633b, Regarding Proposed Judith Gap Wind Power Purchase Agreement, http://www.westgov.org/wieb/meetings/crepcsprg2005/briefing/judithgap.pdf

A. While the Committee believes that $4.64/MWh is a reasonable estimate of PacifiCorp's costs to integrate wind resources within its system, we would like to better understand why the Company has not proposed to capture the impact of wind resource integration costs within its production cost modeling. The Committee still has some outstanding data requests and would like to perform additional modeling runs with GRID to understand if integration costs can be reasonably modeled within GRID. Unfortunately, the Committee has experienced some disk space problems that have prevented it from conducting additional runs concerning this issue, and is working with the Company to resolve these issues. The Committee will present its final recommendation on this issue in its rebuttal testimony.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.