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UM 1129

PUBLIC UTILITY COMMISSION OF OREGON

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OCT 14 2004
Public Utility Commission of Oregon
Administrative Hearings Division

UM 1129

STAFF SURREBUTTAL TESTIMONY

OF

JACK P. BREEN, III
LISA SCHWARTZ
STEVE CHRISS
THOMAS MORGAN
J. R. GONZALEZ

In the Matter of the PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities

October 14, 2004

DOCKETED

CASE: UM 1129
WITNESS: Jack P. Breen III

PUBLIC UTILITY COMMISSION
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Administrative Hearings Unit Division

STAFF EXHIBIT 500

Surrebuttal Testimony

DOCKETED

October 14, 2004

Q. PLEASE STATE YOUR NAME.

A. My name is Jack P. Breen III.

Q. ARE YOU THE SAME JACK BREEN III THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes, I prepared Staff/501, a revised summary of staff's recommendations.

<u>Purpose of Testimony</u>

Q. WHAT IS THE PURPOSE OF STAFF'S SURREBUTTAL TESTIMONY?

A. Staff witnesses Schwartz and Gonzalez provide surrebuttal testimony concerning the second issue (size threshold for standard rates). Staff witness Chriss provides surrebuttal testimony concerning the first issue (natural gas price forecasts, staff's proposed Deadband option, and PGE's proposed market price option). Mr. Chriss also addresses the merits of the SAR methodology as well as the value of capacity during a period of resource sufficiency (Issue 4). Staff witness Morgan provides surrebuttal testimony concerning credit requirements (Issue 3). I provide a new summary of staff's recommendations and I address Mr. Widmer's recommendations concerning the scope of the docket and cost recovery. I also provide surrebuttal testimony regarding the third issue (Utility Tariff Content), the fourth issue (Avoided Cost Calculation Methods, including Idaho Power's proposal to use the SAR methodology approved by the Idaho Public Utilities Commission), and the fifth issue (Applicability of Oregon PURPA Administrative Rules). Staff does not provide surrebuttal testimony regarding the sixth issue (Dispute Resolution).

Summary of Staff's Recommendations

Q. BASED ON STAFF'S REVIEW OF THE INITIAL TESTIMONY, WHAT MODIFICATIONS HAS STAFF MADE TO ITS INITIAL RECOMMENDATIONS?

A. Staff recommends that utilities establish a capacity value for the period when the utility has surplus resources based on the market value of the capacity. Staff also recommends allowing PGE and PacifiCorp to use index rate options.

Q. HAS STAFF PREPARED A NEW SUMMARY OF RECOMMENDATIONS?

A. Yes. A revised summary is provided in Staff/501.

Docket Scope

Q. DO YOU AGREE WITH PACIFICORP WITNESS WIDMER (PPL/100, WIDMER/16) THAT "THIS DOCKET IS LIMITED TO RESOLUTION OF CERTAIN ISSUES FOR QF PROJECTS THAT ARE ENTITLED TO STANDARD RATES"?

A. No. The only issue in this proceeding whose applicability is limited to QF projects of a certain size is Issue 2, which addresses the size limit for standard rates and a standard power purchase agreement.

Cost Recovery

Q. WHAT ARE MR. WIDMER'S COST RECOVERY RECOMMENDATIONS?

A. At PPL/100, Widmer/26-28, Mr. Widmer recommends that utilities receive additional assurance of cost recovery and that the Commission issue orders for filed PURPA contracts finding that the contracts are "just and reasonable for ratemaking purposes."

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. No, these provisions are unnecessary. The basic regulatory compact allows PacifiCorp to recover its prudently incurred costs, including payments to "qualifying facilities" (QFs). As Mr. Widmer acknowledges, he is not aware of any past disallowances by the Commission. The issuance of a Commission order for each contract would add an unnecessary step and result in further delay and uncertainty for the developer. In 2003, PacifiCorp's purchased power expense exceeded $936 million. The level of PacifiCorp's QF purchases pales in comparison to its other power purchases. The Commission does not separately review and issue orders for the much larger power purchases. There is no need for an extra layer of procedure for the relatively small QF power purchases.

Q. WHAT ARE MR. WIDMER'S RECOMMENDATIONS REGARDING COST RECOVERY FOR NATURAL GAS PRICE VOLATILITY?

A. Mr. Widmer recommends (at PPL/100, Widmer/7-8) that if the Commission adopts natural gas price indexing, utilities receive assurance of recovery for any costs related to gas volatility. To do so, he recommends the Commission adopt deferred accounting or a power cost adjustment mechanism, similar to a purchased gas adjustment clause.

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. No. PacifiCorp recovers fuel costs for its own natural gas-fired power plants based on *expected* future gas prices. Yet the company pays for fuel based on *actual* market prices. The way utilities would recover fuel costs under staff's proposed Gas Market Method is consistent with the way they recover fuel costs today for their own power plants. The Deadband Method option also is consistent with traditional utility cost recovery, and provides a greater degree of certainty for the utility.

Q. DO THE UTILITIES HAVE TOOLS AVAILABLE TO PROTECT THEMSELVES FROM THE POTENTIAL RISK OF HIGH NATURAL GAS PRICES?

A. Yes. The utilities have the ability to partake in hedging activities. The Commission would consider a utility's proposal to use prudent hedging if both the benefits and costs are reflected in test period revenue requirements.

Issue 3. Utility Tariff Content

Q. DO YOU AGREE WITH MR. WIDMER (PPL/100, WIDMER/18) THAT UTILITIES SHOULD BE ABLE TO MAKE ADJUSTMENTS TO STANDARD RATES BASED ON PROJECT-SPECIFIC COST CHARACTERISTICS?

A. No, a utility's ability to make adjustments would nullify the use of standard rates and reinsert the utilities into a unilateral negotiating position. Mr. Widmer cites one example of a possible adjustment, where the utility is required to move QF power out of a load pocket that cannot use all of the power. Mr. Widmer fails to cite the more frequent circumstance where contracting with a QF will reduce the company's transmission costs because the QF is generating power at a customer's site, or near customer loads. This proximity is in contrast to utility power plants, which typically are sited far from load centers. Mr. Widmer does not offer to give the QF a premium in those cases.

Q. DO YOU AGREE WITH MR. WIDMER (PPL/100, WIDMER/15) THAT THE UTILITIES SHOULD BE ABLE TO MAKE CHANGES TO THE STANDARD FORM CONTRACTS FOR SMALL QFS THAT THE COMMISSION MAY APPROVE IN CONFORMANCE WITH THE ORDER IN THIS PROCEEDING?

A. No. Allowing the utilities to do so would undermine the purpose of standard contracts.

Q. HOW SHOULD THE COMMISSION ADDRESS THE ISSUE OF THE CAPACITY LIMIT FOR STANDARD RATES AND THE GENERATION OF ENERGY BEYOND THAT LIMIT?

A. The size limit for standard rates and contracts should be based on the manufacturer's nameplate capacity rating. This is a clear standard as requested by PacifiCorp, not subject to manipulation by either party, and verifiable. If a QF is able to generate more energy than the nameplate capacity, the utility would purchase the energy at avoided cost rates. That is fair to the QF and the utility. PacifiCorp's proposal (PPL/100, Widmer/18) to not purchase any energy generated beyond the nameplate rating is unfair and does not reflect the value of the generation to the utility. PGE's proposal (PGE/100, Drennan, Kuns/14) to exclude capacity payments for generation from wind projects greater than 2 MW is similarly unfair.

Q. DO YOU AGREE WITH MR. WIDMER (PPL/100, WIDMER/19) THAT THE UTILITIES SHOULD HAVE THE RIGHT TO TERMINATE A QF CONTRACT IF PURPA IS REPEALED OR THAT THE COMMISSION SHOULD INCLUDE COST RECOVERY ASSURANCE IN ITS ORDER?

A. No. Avoided cost rates constitute fair and just rates for the utility and ratepayers. Utility rates, and hence cost recovery, are based on a utility's revenue requirement. During a rate case, rates are set to recover the utility's expected costs during the period when rates will be in effect. The revenue requirement includes costs associated with purchases from QFs, including payments to QFs and administrative costs. There is no need for the Commission to include additional assurances regarding cost recovery.

Q. **DO YOU AGREE WITH WEYERHAEUSER WITNESS BEACH (WEYERHAEUSER/100, BEACH/12-13) THAT QFS SHOULD HAVE A "SIMULTANEOUS PURCHASE AND SALE" OPTION?**

A. Yes. The utility is required to serve the full requirements of its customers and to purchase 100 percent of the output of a QF at avoided cost rates. The QF should have the option to determine whether to sell to the utility: 1) only excess energy – energy beyond what it needs to meet its own load or 2) all of the energy that the QF produces. Under the second case, the utility would meet the full energy requirements of the QF customer.

Q. **DO YOU AGREE WITH MR. FRYER THAT PACIFICORP AND RATEPAYERS SHOULD BE PROTECTED FROM LITIGATION ARISING OUT OF, OR RELATED TO, THE OPERATION OF A QF (PPL/200, FRYER/2)?**

A. Yes. It is reasonable that the power purchase contract include a mutual hold harmless clause that protects PacifiCorp and ratepayers from the actions of a QF. The problem is PacifiCorp's past insurance practice goes beyond such requirements. For example, Section 11.4 of the generic power purchase agreement (PacifiCorp informational filing, March 2004, Exhibit G) requires the QF to name PacifiCorp as an additional insured and specifies other requirements, such as an "A" rating by the A.M. Best Company. According to the Oregon Insurance Division, there are 824 property and casualty companies operating in Oregon and many have less than an "A" rating. The Oregon Insurance Administrator finds it acceptable for companies to operate with this rating, but PacifiCorp imposes a higher standard.

Q. **DOES PACIFICORP REQUIRE INSURANCE FROM ITS OTHER CUSTOMERS THAT IT INTERACTS WITH UNDER TARIFF?**

A. No. A residential customer can improperly install a home generator and, quoting from PacifiCorp's website, "pose serious safety hazards." However, PacifiCorp does not require these residential customers to maintain a $1 million insurance policy.

Q. **ARE THE SAFETY REQUIREMENTS FOR QFS HIGHER THAN FOR HOME GENERATORS?**

A. Yes. Typically, home generators are installed according to the building code and then remain in place without further inspections. PacifiCorp states the following on its website with regard to the installation of a home generator:

> If you must provide temporary power to your home's wiring system, the generator must be connected through an approved transfer switch that will isolate your house from our system. The switch must comply with the National Electric Code and local building codes. These include permits, inspection and installation by a licensed electrician.

The QF requirements are higher - PacifiCorp conducts additional studies, tests and inspections of QF facilities.

Q. **IS MR. GALE'S AND MR. FRYER'S TESTIMONY (IDAHO POWER COMPANY, GALE, DI-REB – PAGE 12, AND PPL/200, FRYER/3) REGARDING INSURANCE PROVISIONS FOR OTHER VENDORS, OR MR. FRYER'S EXAMPLE OF THE STATE OF OREGON REQUIRING INSURANCE (PPL/200, FRYER/6), COMPARABLE TO REQUIRING QFS TO CARRY INSURANCE?**

A. No. Those vendors make a business decision to sell goods and services to PacifiCorp or to the State of Oregon. QFs are more like other customers that buy service under tariff - their only realistic option is to do business with the utility.

Q. **IS PGE'S EXAMPLE OF THE STATE MANDATING AUTOMOBILE INSURANCE COVERAGE COMPARABLE TO THE ISSUES IN THIS CASE?**

A. No. In 2002, 436 people were killed and 28,348 injured in traffic crashes in Oregon. It is reasonable to mandate coverage in those circumstances. QFs have quite the opposite safety record.

Q. **At PPL/200, FRYER/11, MR. FRYER INDICATES THAT QFS SHOULD CARRY INSURANCE TO PAY PACIFICORP'S LEGAL DEFENSE COSTS TO SETTLE OR TO MITIGATE THOSE COSTS. DOES THIS FOLLOW RATEPAYER NEUTRALITY GUIDELINES?**

A. No. PacifiCorp incurs legal expenses as part of its sale and purchase of energy with all parties. There is no evidence to indicate that its legal costs would be proportionately higher for acquiring QF power. PacifiCorp provides electricity to over 500,000 retail customers in Oregon without requiring those customers to have insurance. Related to its wholesale trading activities, PacifiCorp has recently incurred significant legal costs to defend itself against claims of market manipulation in West Coast power markets.

Issue 4. Avoided Cost Calculation Methods

Q. **DO YOU AGREE WITH PACIFICORP WITNESS WIDMER (PPL/100, WIDMER/28) THAT UTILITIES SHOULD BE PERMITTED TO RE-FILE THEIR AVOIDED COSTS AS SIGNIFICANT NEW RESOURCES ARE DEVELOPED?**

A. No. First, under this proposal, the utilities would file new avoided costs only when they become resource surplus, not resource deficit. Thus, it is unbalanced. Second, the current filing cycle for avoided costs closely follows Commission acknowledgment of the utility's integrated resource plan. This practice should continue.

Q. **MR. GALE (IDAHO POWER COMPANY, GALE, DI-REB – PAGE 3) RECOMMENDS USE OF THE IDAHO SAR METHODOLOGY TO SET IDAHO POWER'S QF RATES IN OREGON. DOES STAFF AGREE WITH THAT PROPOSAL?**

A. Yes, in part. Staff agrees that use of the SAR avoided cost development approach and pricing would result in administrative efficiency. Idaho Power should not be able to modify the avoided cost development approach or pricing that has been adopted by the Idaho Commission. Other matters related to QF power purchases (e.g., contract duration, size limit for standard rates and a standard contract, insurance and security requirements, etc.) should be implemented consistent with the Oregon Commission's decision in this proceeding.

Q. DOES STAFF PROPOSE TO ESTABLISH DIFFERENT PRICES, TERMS, OR CONDITIONS FOR QFS USING RENEWABLE RESOURCES VERSUS COGENERATION?

A. No. The avoided cost methodology provides avoided cost estimates that are suitable for both types of technologies. The terms and conditions staff recommends are also suitable for both technologies.

Q. DO YOU SUPPORT THE POSITION OF THE FAIR RATE COALITION THAT AVOIDED COST RATES FOR SMALL QFS SHOULD BE HIGHER TO REFLECT ENVIRONMENTAL OR COMMUNITY BENEFITS?

A. I do not agree that avoided cost rates should be higher to account for these types of factors. It is my position that the QF retains the tradable renewable certificates (TRCs) when they sell energy to the utility. To add value to their projects, QFs may sell the TRCs to the utility or a third party outside of the QF process.

Q. DO YOU AGREE WITH PGE WITNESSES DRENNAN AND KUNS (PGE/100, DRENNAN/KUNS/11-12) THAT STANDARD RATE CONTRACTS PROVIDE "NO WAY TO RECOGNIZE THE DIFFERENCE IN FIRM AND NON-FIRM SUPPLY AND ITS VALUE TO THE UTILITY SYSTEM"?

A. No. As I stated in my direct testimony (Staff/100, Breen/18), standard contracts can include a mechanical availability guarantee that takes into account the capability of the QF to produce power as well as events that preclude it from making deliveries, such as scheduled maintenance, system emergencies or a force majeure event. Such a guarantee allows the utility to count on QF power as firm. Further, if QFs receive capacity payments only during on-peak hours, they have a strong incentive to deliver energy in those hours. Historical avoided cost pricing in Oregon, and staff's proposed pricing structure, provide capacity payments only for production during on-peak hours.

Q. **SHOULD THE STANDARD CONTRACT FOR QFS THAT CHOOSE THE DAILY MID-C INDEX RATE INCLUDE A MECHANICAL AVAILABILITY GUARANTEE OR OTHER FORM OF FIRM COMMITMENT?**

A. No. The payments the QF receives under the index rate will reflect the market value of the power. The utility can purchase any shortfall in QF energy in the market at the index rate. It is therefore not necessary for the utility to have a guarantee of delivery from small QFs under a standard contract.

Q. **WHAT IS YOUR UNDERSTANDING OF THE "PERFORMANCE BAND" DISCUSSED BY IDAHO POWER WITNESS GALE (IDAHO POWER COMPANY/100, GALE/6)?**

A. Idaho Power uses a performance band in some of its contracts with QFs in Idaho. As I understand it, this provision penalizes QFs if they fail to produce at least 90 percent of the contracted amount of energy or produce more than 110 percent of the contracted amount in any month.

For any shortfall in energy deliveries below 90 percent of scheduled monthly power deliveries, the QFs pay Idaho Power the difference between the contract price and 85 percent of the mid-C index rate – if higher. For energy the QF delivers in excess of 110 percent of the contracted amount, Idaho Power pays 85 percent of the mid-C price or the contract price – whichever is less.

Q. **DO YOU AGREE WITH MR. GALE'S RECOMMENDATION THAT UTILITIES BE ALLOWED TO INCLUDE SUCH A PERFORMANCE BAND IN THE STANDARD CONTRACT FOR QFS ELIGIBLE FOR STANDARD RATES?**

A. No. The utilities should be required to pay standard avoided-cost rates for all energy delivered by QF 10 MW or less. Staff recommends that the standard form of contracts for these QFs include a mechanical availability guarantee to ensure that the utilities can count on the QFs to deliver firm power. The guarantee should not apply to QFs that choose the daily Mid-C index rate.

Q. **DO YOU AGREE WITH DR. LOGAN (PGE /200, LOGAN 18) THAT IT IS APPROPRIATE TO LOWER PAYMENTS TO NATURAL GAS-FIRED COGENERATORS FOR RELIABILITY REASONS?**

A. No. A cogenerator has an incentive to run its generator during high-priced periods by properly designed standby rates.

Cogenerators should pay market prices for the backup energy they purchase.

Q. STAFF NOW RECOMMENDS THAT THE COMMISSION ESTABLISH A MARKET-BASED METHOD TO VALUE AVOIDED CAPACITY COSTS DURING A PERIOD OF UTILITY RESOURCE SUFFICIENCY. DO YOU STILL RECOMMEND LEVELIZATION OF CAPACITY PAYMENTS IN THE EVENT A UTILITY IS RESOURCE-SUFFICIENT?

A. Yes, if the market-based method the Commission chooses allows for a determination of the capacity component of avoided costs. One of the two alternatives that staff witness Chriss recommends (Staff/700, Chriss/10-11) values separately the capacity portion of the avoided costs. Under the second method, capacity values are embedded in forward monthly prices for power.

If the Commission chooses the first method, the avoided capacity costs should be levelized to reflect, beginning in the first year, the value of capacity costs over the entire term of the contract. As I stated in my opening testimony, levelization appropriately compensates QF projects for helping the utility meet expected increases in electricity demand in the future. In addition, if market prices for capacity are low during the resource sufficiency period, levelization of avoided capacity costs might be necessary for QF development.

Further, the Commission should consider that net metering customers receive, for their excess generation, the same standard avoided cost rates as QFs. Unless capacity costs are levelized when a utility is resource-sufficient, these customers likely would get a lower payment for their excess generation than the value to the utility going forward.

Issue 5. Applicability of Oregon PURPA Administrative Rules

Q. PACIFICORP AND PGE WITNESSES CHARACTERIZE YOUR DIRECT TESTIMONY AS A REQUEST TO EXTEND THE EXISTING OREGON PURPA REGULATIONS TO PGE AND PACIFICORP. IS THAT A PROPER CHARACTERIZATION?

A. No. Staff recommends that the Commission revise its Oregon PURPA regulations based on federal PURPA requirements. To the extent that certain Oregon PURPA rules are also authorized under federal PURPA, staff recommends that those regulations carry over to the new rules.

Q. ON WHAT BASIS DO YOU BELIEVE QFS WILL SUFFER FINANCIAL HARM IF THE COMMISSION DOES NOT CORRECT THE ADMINISTRATIVE RULES IN A TEMPORARY RULEMAKING?

A. If the administrative rules are incorrect, that may delay or mislead a QF developer. That would result in financial harm to the QF.

Q. WOULD A TEMPORARY RULEMAKING BE, AS MR. WIDMER CHARACTERIZES IT, A HASTY PROCESS?

A. No. The temporary rule would be put in place during the pendency of the rulemaking. By law, the process will also include a permanent rulemaking.

Q. DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

CASE: UM 1129
WITNESS: Jack P. Breen III

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STAFF EXHIBIT 501

Exhibit in Support of Surrebuttal Testimony

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REVISED SUMMARY OF STAFF'S POSITION

Issue 1. Contract Length and Price Structure

- The utilities should be required to offer QFs a contract term up to 15 years, at the QF's discretion.
- The utilities should use two pricing methodologies to calculate the energy cost portion of avoided cost calculations. The Deadband Method uses a natural gas forecast with floor and ceiling prices. The Gas Market Method uses a monthly indexed price with no forecast.
- PGE should be allowed to offer QFs an additional option: Dow Jones Mid-C Index rates. At PacifiCorp's option, the company should be allowed to offer power market index rates that reflect its system.
- QFs up to and including 2 MW should be able to choose the Deadband Method, the Gas Market Method, power market index rates (if the utility chooses to offer them), and a fixed pricing option based in part on forecasted natural gas prices. QFs over 2 MW, up to and including 10 MW, should be able to choose any of these options except fixed pricing.
- Utilities should not be required to offer levelized rates to QFs. (See Issue 4 for levelization of capacity payments during a period of utility resource sufficiency.)
- QF payments should be established for the entire term upon execution of the power purchase agreement, based on the utility's approved avoided cost stream at that time. Payment amounts for existing contracts should not be updated when the Commission approves new avoided cost filings.

Issue 2. Size Threshold for Standard Rates

- QFs up to and including 10 MW (nameplate capacity) should be eligible for standard, non-negotiated purchase rates and a standard power purchase agreement.

Issue 3. Utility Tariff Content

- Approved 20-year avoided costs should be published in the utility's tariffs.
- QFs eligible for standard rates should receive standard contract terms and conditions, and the contracting utility should file the standard contract form for Commission approval, along with the avoided cost tariff.
- The utility's tariff should indicate that prices for QFs eligible for standard rates are determined upon initial execution of the contract for the term of the contract.
- The utility's tariff should specify that for QFs exceeding the size threshold for standard rates, the 20-year avoided costs form the basis for contract negotiations, as well as specify the factors that the utility may consider in adjusting the avoided costs upward or downward to reflect the project characteristics.
- Tariffs and contracts for QFs eligible for standard rates should not allow adjustments for project-specific characteristics related to delivery of energy and capacity to the purchasing utility.
- The utilities should not be allowed to terminate a contract with a QF if the federal PURPA law is repealed.

- The utilities should not be allowed to mandate the type and level of QF insurance coverage for QFs eligible for standard rates and a standard contract.
- The standard form of power purchase agreement for QFs that are eligible for standard rates should include risk management provisions consistent with the following:
  - A performance bond may be required to ensure timely completion of project construction. A letter of credit or escrow deposit should not be required.
  - A letter of credit or escrow deposit should not be required as default security for operational risk.
  - Weather-related reductions in resource availability should not trigger default events.

Issue 4. Avoided Cost Calculation Methods

- The Commission should maintain the historical method for calculating avoided costs for periods when the utility is resource-deficit, using the estimated capacity and energy costs of new resources.
- The Commission should adopt a new method for setting avoided costs for periods when the utility is resource-sufficient, until projected supply deficits occur. Staff recommends two possible alternatives:
  - *The variable cost of operating existing generating facilities plus the price of capacity in the relevant wholesale capacity market.* If the Commission chooses this method, staff recommends levelizing

payments for avoided capacity costs for QFs eligible for standard rates.

- *Monthly on- and off-peak forward power prices at the time of the avoided cost filing.* Under this method, avoided capacity cost payments would not be levelized over the term of the contract.

- Avoided cost payments for QFs eligible for standard purchase rates should include both energy and capacity costs, even if the QF uses an intermittent resource.
- Avoided costs should be developed for a fixed set of prices and an indexed set of prices.

Issue 5. Applicability of Oregon PURPA Administrative Rules

- The Commission should open a temporary rulemaking to modify the Division 29 Administrative Rules to acknowledge federal PURPA as the primary basis and to correct inconsistencies between federal and state definitions of avoided costs.

Issue 6. Dispute Resolution

- The Commission should retain its current policy where staff does not participate in informal mediation in utility/QF contract disputes.

CASE: UM 1129
WITNESS: Lisa Schwartz

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STAFF EXHIBIT 600

Surrebuttal Testimony

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Q. PLEASE STATE YOUR NAME.

A. My name is Lisa Schwartz.

Q. ARE YOU THE SAME LISA SCHWARTZ THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. DID YOU PREPARE AN EXHIBIT?

A. Yes. I prepared Staff/601, which consists of four pages.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide surrebuttal testimony regarding the second issue in this proceeding, size threshold for standard avoided cost rates and a standard power purchase agreement.

Issue 2. Size Threshold for Standard Rates and Contracts

Q. DO YOU AGREE WITH MR. WIDMER'S ASSERTION (PPL/100, WIDMER/9) THAT MOST QFS RECEIVING STANDARD RATES ARE BEING SUBSIDIZED?

A. No. Staff's proposed methodology for calculating standard avoided costs is a reasonable estimate of the costs the utility will avoid by purchasing from the QF. Therefore, standard avoided cost rates do not constitute a subsidy.

Actual costs the utility avoids for a particular project may be higher or lower than the estimates. For example, the installation of a cogeneration unit at a customer's site may alleviate constraints on the electric grid and reduce the utility's cost for required upgrades or transmission costs, but the utility does not pass that benefit on to the QF. Unlike utility power plants, which typically are located far from load centers, QFs can be located at a customer's site or near customer loads.

Further, cogeneration and biomass QFs are baseload, not intermittent, resources. They do not require the imbalance services that Mr. Widmer states are an additional cost posed by wind resources.

In addition, utilities are not paying QFs for reserves through avoided cost rates. That is because the avoided cost calculations do not take into account the cost of reserves for the proxy utility plant. In other words, both the QF and the proxy utility plant would pose additional costs for reserves. If the QF is a natural gas-fired resource, the reserves cost would be the same per megawatt as the proxy utility plant. So it is incorrect to say that because standard avoided cost rates do not include the cost of reserves, the rates constitute a subsidy.

Q. DO YOU AGREE WITH MR. WIDMER'S ANALYSIS (PPL/100, WIDMER/10) WHICH ATTEMPTS TO "PROVIDE AN EXAMPLE OF HOW TO QUANTIFY THE SUBSIDY PAID TO A REMOTE INTERMITTENT RESOURCE SUCH AS TO A QF WIND DEVELOPER"?

A. No. Mr. Widmer's analysis assumes an integration cost of $5.50 for the wind resources, composed of a $3.00/MWh cost for imbalance services and a $2.50/MWh cost for reserve requirements. This assumption is incorrect for two reasons:

First, these figures are for the addition of more than a *thousand* megawatts of wind resources to PacifiCorp's system, not the addition of 1 MW, 5 MW and 10 MW wind projects Mr. Widmer uses in his example.

As shown in Figure L.1 on page 367 of PacifiCorp's 2003 Integrated Resource Plan (Staff/601, Schwartz/1), the imbalance cost of adding a 10 MW wind project to PacifiCorp's system is certainly less than a dollar per MWh. That is the approximate cost of integrating nearly 200 MW of wind resources on the West side of the company's system. In addition, the caveats in the resource plan analysis (pp. 369-370) reveal that the modeling used to estimate these imbalance costs did not account for changes in the dispatch of hydro resources that can reduce imbalance costs. (*See* Staff/601, Schwartz/2-3.)

As for reserve requirements, Figure L.2 on page 368 of the company's 2003 resource plan (Staff/601, Schwartz/4) shows that the reserve requirement for the addition of 10 MW of wind resources is near zero.

Second, as I pointed out in my answer to the previous question, the avoided cost calculations do not consider the cost of reserves for either the proxy utility plant or the QF.

Q. **DO YOU AGREE WITH MR. WIDMER (PPL/100, WIDMER/12) THAT THE COMMISSION SHOULD ACKNOWLEDGE THAT MINIMIZATION OF QF TRANSACTION COSTS IS THE RATIONALE FOR ESTABLISHING THE SIZE LIMIT FOR STANDARD RATES?**

A. No. That is only one factor the Commission should consider. The utilities recognize that the Commission can make a policy decision regarding the size limit for standard rates and a standard power purchase contract. In making this decision, the Commission should consider all the disadvantages faced by small QFs that are forced to negotiate.

In addition to QF transaction costs, the lack of transparency inherent in negotiated rates, terms and conditions is a key consideration the Commission should take into account in determining the size limit for standard rates and contracts. The Commission also should consider how delays resulting from negotiations with the utility, in some cases lasting longer than a year, can kill proposed QF projects. Further, the Commission should consider how contract terms and conditions that are unnecessarily burdensome can make a project uneconomic and unable to obtain financing. Finally, the Commission also might consider how expanded use of standard rates and contract terms would reduce utility costs associated with QF negotiations.

Q. **AS JUSTIFICATION IN PART FOR A THREE MW SIZE LIMIT FOR STANDARD RATES AND CONTRACTS, MR. WIDMER (PPL/100, WIDMER/13) STATES THAT "THREE MW ALSO ROUGHLY CORRESPONDS TO THE LEVEL AT WHICH A QF WOULD HAVE TO INTERCONNECT WITH THE TRANSMISSION AS OPPOSED TO DISTRIBUTION SYSTEM." IS THAT CONSISTENT WITH YOUR EXPERIENCE?**

A. No. For example, SP Newsprint last year connected 94 MW of new cogeneration capacity at the sub-transmission level to PGE's system. Weyerhaeuser has a 47 MW combined-cycle turbine and a 45 MW steam turbine connected to PacifiCorp's system at the primary voltage distribution level. Staff witness Gonzalez addresses the technical merits of PacifiCorp's argument for the lower distribution voltages. (See Staff/900.)

Q. **IF THE COMMISSION SETS THE QF SIZE LIMIT FOR STANDARD RATES AT LESS THAN 10 MW, SHOULD THE UTILITIES BE REQUIRED TO FILE FOR COMMISSION APPROVAL A STANDARD CONTRACT FORM FOR QFS AS LARGE AS 10 MW?**

A. Yes. The Commission should recognize that the utilities today include unnecessarily burdensome provisions for small QFs related to security and other matters. Such contract terms can make a project uneconomic and unable to obtain financing. Negotiations over such provisions also are more complex and lengthy than negotiations over prices. The Commission should require that the utilities file for approval a standard contract form for QFs with a nameplate capacity 10 MW or less, regardless of whether the Commission sets a lower limit for standard avoided cost rates.

Q. DO YOU AGREE WITH MR. WIDMER (PPL/100, WIDMER/3) THAT PROVIDING STANDARD CONTRACTS TO SMALL QFS ON "FAVORABLE TERMS AND UNAVAILABLE TO OTHER COMMERCIAL COUNTERPARTIES" WOULD VIOLATE THE INTENT OF PURPA?

A. No. First, PURPA sets QFs apart from other commercial counterparties. The purpose of the federal law is to facilitate QF development, so long as the utility pays no more for the QF power than the utility's avoided costs.

Second, federal PURPA regulations define avoided costs as "...the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, *such utility would generate itself* or purchase from another source." [*Emphasis added.*] (*See* 18 CFR 292.101(b)(6).) Mr. Widmer fails to address the relative level of risk exposure for ratepayers of small QF contracts vs. large utility-owned power plants, where utilities enjoy favorable adjustment mechanisms when their operating costs increase. Such mechanisms include general rate cases, an annual Resource Valuation Mechanism and deferred accounting – all of which are unavailable to QFs.

Q. DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

CASE: UM 1129
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 601

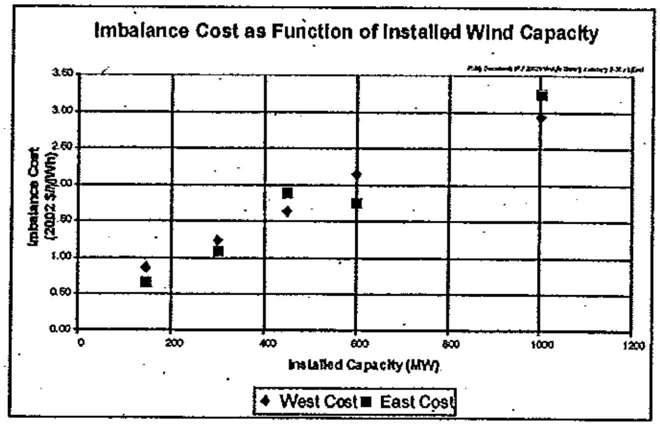
Exhibit in Support of Surrebuttal Testimony

October 14, 2004

capacity. The three years did not show a consistent increase or decrease in costs over time. This result was attributed to resource additions in intervening years. For consistency, PacifiCorp averaged the three years to estimate imbalance costs.

The results of the analysis are presented in the chart below. The model showed relatively little difference between the east and west sides of the PacifiCorp system. At wind penetration levels of 1,000 MW PROSYM reports average imbalance costs of about $3/MWh. This confirms that costs increase with penetration levels. The costs assessed by PROSYM appear to increase roughly linearly with installed capacity at the levels tested in the model.

Figure L.1 Wind Imbalance Costs



INCREMENTAL OPERATING RESERVE REQUIREMENTS

Incremental reserve requirements were estimated by comparing the relative dynamic range of loads with and without wind. The standard deviation of hourly loads for a year was calculated. A new standard deviation was computed after subtracting out various levels of wind generation. The fractional difference in standard deviations was taken as an estimate of the increased need for operating reserves. Results are presented in the chart below. Note that the relative increase is larger on the west side for a given wind penetration level. This is due to west side loads being generally lower than on the east side. A given level of wind capability therefore represents a higher fractional penetration on the west side than on the east. In the range of wind capability levels examined, the incremental reserve requirement can reasonably be described by a quadratic polynomial.

Where C_w = incremental reserve requirement Cost (2002 \$/MWh)
P_w = installed wind capacity (MW)
f = average wind capacity factor
A = 5.74E-4 East, 2.46E-4 West
B = 0.243 East, 0.365 West

Example

Locate 500 MW of wind capacity in Utah, with a capacity factor of 35%

The Cost per MWh for incremental reserve requirements would be:
.000574 X 500 / .35 + .243/.35 = 1.51 \$/MWh

For 1,000 MW at an average 30% capacity factor, the cost would be 2.72 \$/MWh.

Similar resources located on the west side would cost \$1.39 and \$2.04 respectively.

Caveats

The foregoing analysis is thought to represent a reasonable approach to estimating costs associated with integrating wind resources into PacifiCorp's power system until further analysis can be performed. Many assumptions have necessarily been made to do this analysis. Some of the main assumptions include:

1. PROSYM ability to accurately reflect imbalance costs
   PROSYM dispatch model logic has complete foreknowledge of wind generation in its unit commitment logic. This probably leads to undercounting some costs associated with unit start-ups. The extent of the error depends to some extent on the ability of forecasters to forecast wind output at least a day in advance. Alternatively, PROSYM assumes a hydro dispatch without consideration of wind generation. This tends to overestimate the imbalance costs, especially on the west side of the system where there is a significant amount of hydro.

2. Operating reserve requirements are proportional to hourly load volatility net wind generation.
   This assumption appears to be reasonable, but has no firm theoretical foundation. In fact, it is not clear whether operating reserves represent a sufficient mechanism for integrating large amounts of wind. For example, it may be necessary to increase system flexibility to decrease generation, not just increase generation as represented by operating reserves. Current practice for reserves was developed from many years of operating experience—experience lacking for large amounts of wind generation. While the analytical framework for the analysis appears reasonable, experience may well suggest more refined and accurate techniques for assessing wind integration costs.

3. Cost of reserves remains relatively constant relative to market prices.

The cost of reserves is dependent on the difference between the variable costs of PacifiCorp's marginal resource and the market price for power. The cost of holding reserves will tend to increase with high market prices, and decrease with lower market prices. Costs calculated in this analysis are based on current projections of market prices and PacifiCorp resource costs and represents a snapshot based on an assumed wind pattern and market price shape. Further stochastic analysis will likely be required in order to determine a range of outcomes. The risk model is not yet able to simulate the stochastic process of wind.

4. Sufficient transmission to fully integrated wind resources with the system.
   Wind resources are often located far from load centers. The analysis here assumes wind resources have strong interconnection with the balance of the system.

5. Intra-hour variability is not significant.
   Experience to date suggests the intra-hour variability of wind generation does not result in a material a cost issue. However, this assumption is based only on the observations of operations and may change if the wind resoucre capacity is vary large or very centralized. A high level of intra-hour variability for a given wind project is likely to result in the need for increased spinning reserves by operators in order to maintain compliance with then-current reliability criteria. In addition, a high level of intra-hour variability could introduce financial imbalance risk in the event future market imbalance rules penalize wind generation in the same fashion as other forms of generation resources.

6. RTO
   Cost calculations are necessarily based on historical practice relative to future price expectations. The RTO, as discussed in Chapter 3, represents a significant future Paradigm Risk. As with any Paradigm Risk, RTO rules and guidelines, when finally implemented, could affect the cost calculations positively or negatively.

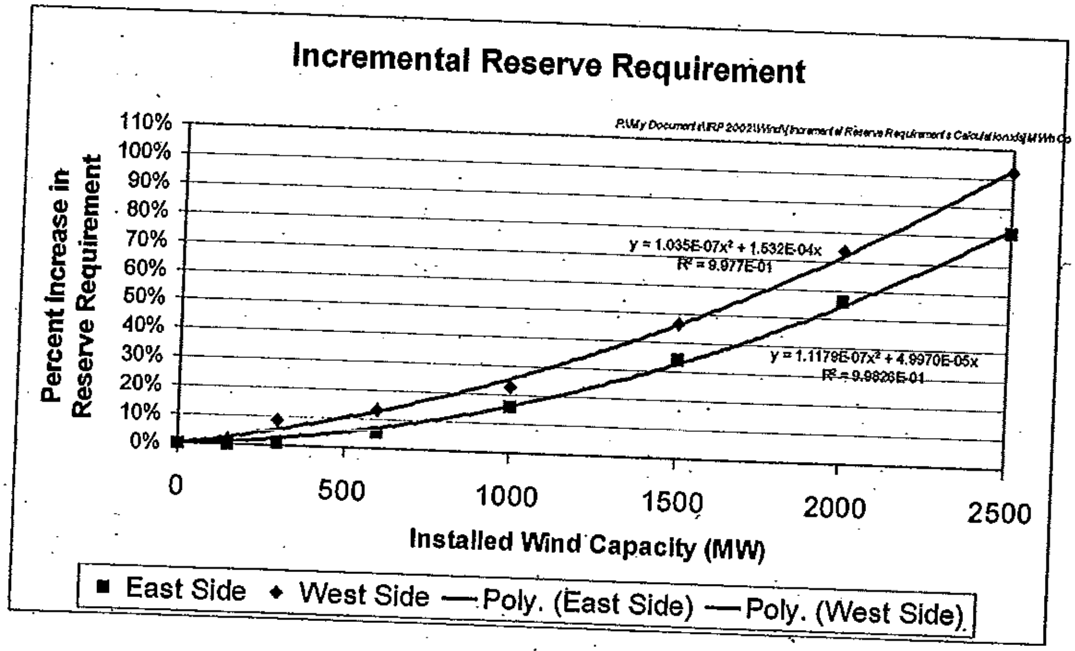
TOTAL WIND RESOURCE COSTS

The foregoing analysis considered system costs specific to integrating wind power facilities into PacifiCorp's control area. Total system costs of wind power also include power plant and facility capital costs, operations and maintenance costs, transmission facilities costs, and consideration of the federal production tax credit and valuation of renewable energy credits ("green tags"). PacifiCorp used the following assumptions in arriving at total wind resource costs.

<u>Wind Resource Cost Assumptions</u>

Capital Costs ($2002/kW)	$1000
O&M ($2002/kW)	$22.65
Economic Life	20 years
Transmission Cost ($2002/MWh)	$2-6
Production Tax Credit ($2002/MWh)	($12)
Renewable Energy credit ($2002/MWh)	($2)

Figure L.2 Wind Incremental Reserve Requirement



Assuming that the fractional increase in standard deviation of hourly loads with and without wind is proportional to the increased need for reserves, the incremental need for reserves can be estimated. Factoring in the cost of reserves results in an estimation of the cost of incremental operating reserves attributable to wind.

Operating reserves are typically held on hydro units when available, and higher variable cost thermal units to the extent they are needed. PacifiCorp holds an existing portfolio of resources that can be arranged from highest variable cost to lowest. Holding reserves on unloaded hydro units, and above-market-cost thermal units incurs relatively little cost. However, as the need for reserves increases, the likelihood of having to carry reserves on economic thermal units and loaded hydro units increases. This means that the costs of holding reserves increases with the level of reserves being held. Costs of holding reserve may increase over time due to increases in overall market prices[28]. Also important is the type of resource additions over time.

The foregoing makes clear that generally, the cost of reserves is not a linear function. However, at incremental levels examined, the relationship between cost of holding reserves and the amount held was nearly linear. As a result, the cost per MWh of wind capacity additions will increase linearly with the added capacity. A formula was developed to express the cost of incremental reserves required and is displayed below:

$$C_w = A\frac{P_w}{f} + B/f$$

[28] The cost of reserves also changes over hours and season. The calculation here assumes an average cost over the year.

CASE: UM 1129
WITNESS: Steve Chriss

PUBLIC UTILITY COMMISSION OF OREGON

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OCT 15 2004
Public Utility Commission of Oregon
Administrative Hearings Unit Division

STAFF EXHIBIT 700

Surrebuttal Testimony

DOCKETED

October 14, 2004

Q. PLEASE STATE YOUR NAME.

A. My name is Steve Chriss.

Q. ARE YOU THE SAME STEVE CHRISS THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Staff/701, which consists of one page.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide surrebuttal testimony regarding the issue of Contract Length/Price Structure. Specifically, I address statements by witnesses from the utilities and interveners regarding natural gas price forecasts, the Deadband Method, and power market pricing options. I also address the Idaho Surrogate Avoided Resource methodology and QF capacity value during a period of utility resource sufficiency (Issue 4, avoided cost methodology).

Natural Gas Price Forecasts

Q. ODOE WITNESS CARVER PROPOSES THE COMMISSION ESTABLISH A BASE-CASE FORECAST FOR NATURAL GAS PRICES TO BE USED IN AVOIDED COST AND LEAST-COST PLANNING

PROCEEDINGS (ODOE/1, CARVER/5, LINE 15). DO YOU SUPPORT THIS RECOMMENDATION?

A. No. Dr. Carver recommends that PUC staff develop 20-year natural gas price forecasts for the three local trading hubs, Sumas, Opal and Stanfield. Staff would develop these forecasts every two years, and the Commission would review them in a contested case proceeding. In addition, staff would propose what weights to apply for these trading hubs for PacifiCorp and PGE. The Commission would require that the utilities use the approved forecasts and weights in their integrated resource plans (IRPs) and avoided cost filings.

Today, each utility develops its own natural gas price forecast for its biennial resource plan, for what it believes is the appropriate trading hub or combination of hubs. After the Commission acknowledges the resource plan, the utility makes its avoided cost filing, which relies in part on its updated natural gas price forecast, submitted with the filing. The updated forecast accounts for the time lag between developing the resource plan and filing avoided costs. For example, PacifiCorp made its most recent avoided cost filing more than a year after it developed the natural gas price forecast it used in its January 2003 resource plan. Staff and other parties can challenge the updated forecast during the avoided cost filing process and ensure that it continues to be reasonable.

It is important to maintain consistency in the natural gas price forecasting method a utility uses for its resource plan and avoided cost filing. It is also important to update the natural gas price forecast at the time of the avoided cost filing. Further, staff agrees with PacifiCorp that a staff-developed forecast would not necessarily match how the utilities make decisions to operate their systems in the near term. (However, no current forecast of natural gas prices will determine how the utility operates its system in the long run, in large part because of volatility in natural gas and power prices.)

At the same time, staff recognizes that parties tend to wait until the utility files its draft IRP to review and critique the company's natural gas price forecast. However, this does not have to be the case. Parties should start reviewing the company's natural gas price forecasting methodologies early in the IRP process and communicate any concerns to the utility. Any remaining disputes will then be fully delineated by the time the utility files its IRP. The Commission can then arbitrate disputes in its acknowledgment order.

Formalizing this review process may be beneficial. Therefore, staff plans to recommend to the Commission in the least-cost planning investigation (UM 1056) that the following issue be added: When and how should the Commission review the utility's natural gas price forecast? One solution may be to set a deadline for IRP proceedings by which the utilities would be required to present their forecasting methodologies and resulting natural gas prices. The deadline should be far enough in advance of the draft IRP filing to allow sufficient time to review and critique the forecasts.

Q. WOULD ALLOWING THE UTILITIES TO CONTINUE PERFORMING THEIR OWN NATURAL GAS PRICE FORECASTS NECESSARILY RESULT IN LOWER AVOIDED COST RATES THAN WOULD BE ESTABLISHED IN AN AVOIDED COST PROCEEDING?

A. No. Allowing the utilities to continue performing their own natural gas price forecasts is not a free pass to develop low avoided cost rates for QFs, as Dr. Carver suggests (ODOE/1, Carver/7, Line 1). Staff and other parties have the ability to challenge the forecasts during the avoided cost filing process and ensure that the forecasts are reasonable for the utility, its customers, and QFs.

Q. SHERMAN COUNTY COURT/J.R. SIMPLOT CO. WITNESS HAWK PROPOSES THAT THE COMMISSION ESTABLISH AT $6 PER MMBTU, WITH AN ESCALATION RATE OF ZERO, THE INITIAL NATURAL GAS PRICE USED IN PART TO DETERMINE AVOIDED COSTS (SHERMAN, SIMPLOT, HAWK/7, LINE 3). DO YOU SUPPORT THIS RECOMMENDATION?

A. No. Staff recommends that the utilities continue to develop their own natural gas price forecasts for their resource plans and avoided cost filings.

Q. PGE (PGE/100, DRENNAN, KUNS/19, LINE 1) PROPOSES THE USE OF AN ANNUAL INDEX FOR NATURAL GAS PRICES INSTEAD OF A

MONTHLY INDEX AS PROPOSED BY STAFF FOR ITS GAS MARKET METHOD. DO YOU SUPPORT THIS RECOMMENDATION?

A. No. As stated in my testimony (Staff/300, Chriss/11, Line 9), the use of indexing better reflects the actual market price for electricity, so utilities and customers pay prices to QFs that reflect their opportunity costs. A monthly index is the best way to put this premise into practice, as it is granular enough to capture monthly and seasonal variations in natural gas prices, but not as administratively unruly as using daily prices. Using an annual index would mask monthly and seasonal variations in natural gas price, thus muting price signals to the QFs and reducing the benefits of allowing prices to reflect opportunity costs.

<u>The Deadband Method</u>

Q. **PGE WITNESSES DRENNAN AND KUNS (PGE/100, DRENNAN, KUNS/22) ASSERT THAT IF THE PURPOSE OF THE "BANDED RATE" IS TO PROVIDE QFS WITH "ESSENTIALLY A FIXED PRICE STREAM," THEN "THAT OBJECTIVE NEEDS TO BE STATED EXPLICITLY." DOES THE DEADBAND METHOD ESSENTIALLY PROVIDE A FIXED PRICE STREAM?**

A. No. The Deadband Method provides prices fixed within a range of values, not prices fixed to specific values. As I stated in my direct testimony (Staff/300, Chriss/8, Line 11), the Deadband Method provides QFs more stable pricing than the Gas Market Method, because it has known forecast natural gas prices, floors, and ceilings. QFs have the potential to get higher rates than under traditional fixed pricing, if actual natural gas prices are higher than forecasted prices. QFs also have a reduced downside compared to the Gas Market Method when actual natural gas prices are lower than forecasted.

Q. HOW DOES THE DEADBAND METHOD DIFFER FROM A FIXED PRICE STREAM?

A. The Deadband Method captures some of the potential volatility in the natural gas market, which a fixed price stream does not do. Under the Deadband Method, the QF gets the actual natural gas price for the month, so long as it is within 90 percent and 110 percent of forecasted prices (the floor and ceiling rates). Therefore, the Deadband Method reflects some of the opportunity cost to the utilities and customers caused by changes in the price of natural gas. Fixed pricing does not account for any changes in natural gas prices.

Q. PLEASE EXPLAIN YOUR ANALYSIS WHICH FURTHER SUPPORTS THIS CONCLUSION.

A. As I stated in my direct testimony (Staff/300, Chriss/7, Line 8), I based my recommendation for the 90 percent and 110 percent deadbands on my analysis of the coefficient of variation of the price forecast for the average of the Sumas, Opal, and Stanfield hubs (SOSA). I provide that analysis in Staff/701. Based on statistical theory, the deadbands should account for

68 percent of the values from the forecast.[1] In practice, for SOSA, the deadbands account for 82 percent of the values from the forecast for the period studied. As a result, a good deal of the potential opportunity costs to the utilities, customers, and QFs are captured within the deadbands.

Market Prices for QF Power

Q. PGE WITNESSES DRENNAN AND KUNS PROPOSE A DOW JONES MID-C INDEX RATE OPTION IN THEIR TESTIMONY (PGE/100, DRENNAN, KUNS/20, LINE 9). DO YOU AGREE THAT THIS IS A VIABLE OPTION?

A. For PGE, yes.

Q. HOW WOULD MID-C INDEX PRICING BENEFIT PGE AND ITS CUSTOMERS?

A. A Mid-C Index option would allow PGE to purchase QF power at the price that most likely represents the utility's opportunity cost. As well, market prices give QFs an incentive to produce during the highest-price periods, when the power is most valuable to the utility. PGE and its customers also may benefit in off-peak hours, when during times of the year market prices likely would be lower than the avoided energy cost rate. In my direct testimony (Staff/302, Chriss/8-9), I show that, with the exception of an initial spike, Mid-C off-peak prices for the months in the analysis are

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[1] The value is more precise the closer the distribution of the variables is to the normal distribution.

lower than the calculated off-peak prices for the Deadband Method, Gas Market Method, and traditional avoided cost method.

Q. **HOW WOULD A MID-C INDEX OPTION BENEFIT QFS?**

A. As Drennan and Kuns state (PGE/100, Drennan, Kuns/20, Line 13), Mid-C Index prices would benefit QFs that have only minimal supply commitments to the utility. QFs with the ability to control the amount of power they supply to the utility, including self-generating customers that can reduce on-site load to boost generation, could take advantage of peak market prices that may be higher than those available through other pricing options.

Q. **SHOULD PACIFICORP BE REQUIRED TO OFFER THE MID-C INDEX OPTION?**

A. No. PacifiCorp's system operates differently than PGE's system, and the Mid-C Index Rate may not accurately represent where PacifiCorp buys power when it goes to market. Staff encourages PacifiCorp to explore offering a power market-based option and believes that PacifiCorp is best suited to decide which hubs should be used in the index prices.

Idaho Surrogate Avoided Resource (SAR) Methodology

Q. **PACIFICORP WITNESS WIDMER STATES THAT THE COMMISSION SHOULD NOT ADOPT THE SAR METHODOLOGY (PPL/100, WIDMER/20, LINE/6). DO YOU AGREE WITH THIS STATEMENT?**

A. Yes. With the exception of Idaho Power's use of SAR for administrative efficiency (see Staff/500, Breen/12), staff recommends that the Commission not adopt the SAR methodology. Staff has no strong disagreements with Mr. Widmer's findings regarding SAR, though two areas need to be reinforced.

Q. WHAT IS THE FIRST AREA THAT SHOULD BE REINFORCED?

A. Mr. Widmer points out that the SAR methodology produces a single $/MWh price that applies to all QF generation regardless of season or time of day (see PPL/100, Widmer/20, Line 12). This would be a step backwards from the current avoided cost methodology, which provides an incentive for QFs to deliver power when it is needed most by utility systems: during peak periods. In addition, the SAR method does not allow for prices that reflect the opportunity costs of the utilities and customers, which is a primary benefit of staff's recommended calculations of avoided costs (see Staff/300, Chriss/11, Line 9).

Q. WHAT IS THE SECOND AREA THAT SHOULD BE REINFORCED?

A. Mr. Widmer also identifies the problem with SAR's elimination of the utility resource surplus period (see PPL/100, Widmer/22, Line 15). The result can be an overpayment to QFs for capacity during times when QF purchases are not avoiding capacity additions. Staff agrees with this statement in part, but also believes that capacity will always have some positive value because the utilities can sell equivalent capacity into the market.

Valuing Capacity When a Utility Is Resource-Sufficient

Q. DO YOU AGREE WITH ODOE WITNESS CARVER (ODOE/1, CARVER/4, Lines 2-24) THAT IT IS INAPPROPRIATE TO VALUE AVOIDED CAPACITY COSTS AT ZERO DURING A PERIOD WHEN THE UTILITY IS RESOURCE-SUFFICIENT ?

A. Yes. Dr. Carver argues that even when a utility is resource sufficient, surplus capacity has positive value, either in the market as previously stated or as a tool for reliability needs. Staff agrees that capacity has value during periods of utility resource sufficiency and thus a capacity value of zero during these periods is not a reasonable choice.

Q. HOW SHOULD AVOIDED COST PAYMENTS TO QFS DURING PERIODS OF UTILITY RESOURCE SUFFICIENCY BE SET?

A. Staff recommends two possible alternatives for setting avoided cost payments to QFs during periods of utility resource sufficiency:

1. The variable cost of operating existing generating facilities plus the price of capacity in the relevant wholesale capacity market. Utilities would propose, using a methodology of their choice, a market price of capacity at the time of their avoided cost filing. Because this price represents the opportunity cost to utilities and QFs, the methodology is consistent with our market-based recommendations for the energy portion of payments to QFs. If the Commission chooses this method, staff recommends levelizing the avoided capacity payments for QFs eligible for standard rates (*See* Staff/500, Breen/16).

2. In lieu of an avoided cost calculation, the utility would set QF payments for the period of resource sufficiency to monthly on-peak and off-peak forward prices at the time of the filing. Under this method, avoided capacity cost payments would not be levelized over the term of the contract.

Summary of Pricing Options

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION FOR QF PRICING OPTIONS.

A. Staff recommends the following pricing options for QFs up to and including 2 MW:

1. A fixed price option.
2. The Deadband Method option, with prices tied to a monthly natural gas forecast with floor and ceiling prices.
3. The Gas Market Method option, with prices tied to a monthly indexed price.
4. For PGE, the Dow Jones Mid-C Index rate option.
5. At PacifiCorp's option, power market index rates that reflect its system.

QFs over 2 MW would be able to choose all of these methods except the fixed price option.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1129
WITNESS: Steve Chriss

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STAFF EXHIBIT 701

Exhibit in Support of Surrebuttal Testimony

DOCKETED

October 14, 2004

Coefficient of Variation Analysis for Sumas, Opal, Stanfield, and SOSA Forecasts, July 2001 through June 2016

Hub	Average	Standard Deviation	High Value - One Standard Deviation	Low Value - One Standard Deviation	Coefficient of Variation	Percent of Values Within One Standard Deviation
	(1)	(2)	(3)	(4)	(5)	(6)
			(1) + (2)	(1) - (2)	(2) / (1)	
Sumas	$ 3.71	$ 0.58	$ 4.29	$ 3.13	0.16	89%
Opal	$ 3.45	$ 0.28	$ 3.73	$ 3.16	0.08	73%
Stanfield	$ 3.67	$ 0.35	$ 4.02	$ 3.32	0.09	81%
SOSA	$ 3.61	$ 0.36	$ 3.97	$ 3.24	0.10	82%

CASE: UM 1129
WITNESS: Thomas Morgan

PUBLIC UTILITY COMMISSION OF OREGON

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OCT 14 2004
Public Utility Commission of Oregon
Administrative Hearings Unit Division

STAFF EXHIBIT 800

Surrebuttal Testimony

DOCKETED

October 14, 2004

Q. PLEASE STATE YOUR NAME.

A. My name is Thomas Morgan.

Q. ARE YOU THE SAME THOMAS MORGAN THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide surrebuttal testimony concerning one aspect of the third issue, Utility Tariff Content. Specifically, I address statements by PacifiCorp's witnesses regarding the credit requirements utilities should be allowed to impose on small QFs that are eligible for a standard form of contract.

Credit Requirements

Q. DO YOU AGREE WITH MR. WIDMER (PPL/100, WIDMER/3) AND MS. WESSLING (PPL/300, WESSLING/2) THAT CONTRACT TERMS AND CONDITIONS, SUCH AS CREDIT AND SECURITY REQUIREMENTS, SHOULD BE THE SAME FOR SMALL QFS AS FOR OTHER COMMERCIAL-SCALE GENERATION COUNTERPARTIES?

A. No. PURPA was designed to facilitate QF development, while at the same time ensuring that ratepayers would not pay more for power from QFs than they would from other resources, including power generated by the utility. PacifiCorp's witnesses Widmer and Wessling address only how they believe contract terms and conditions for small QFs should be at parity with other commercial-scale generation counterparties. The witnesses do not, however, address the relative impact to ratepayers of small QF contracts compared to utility-owned resources.

As I pointed out in my direct testimony (Staff/400, Morgan/15-16), ratepayers are exposed to volatility due to utility-owned resources through a variety of cost recovery mechanisms, including general rate cases, the Resource Valuation Mechanism, deferred accounting and automatic adjustment clauses. Conversely, these cost recovery mechanisms protect the utilities from the rate volatility the ratepayers experience. Unlike the utilities, QFs do not benefit from such protections and cannot pass onto ratepayers higher than reasonably-expected costs that have not been figured into their contracts. For example, extreme fluctuations or extraordinary costs for fuel or maintenance – including catastrophic failure – may not be included in contract provisions. In such cases, a smaller QF may not have the same protections from risk afforded utilities via the expectation of Commission support to remedy unreasonable outcomes.

In short, the default security requirements that PacifiCorp proposes may cause small QFs to bear increased operational risk than the amount of risk to which the utilities and their stockholders are exposed. That would not appear to constitute neutral treatment for QFs.

Q. DO YOU AGREE WITH MS. WESSLING (PPL/300, WESSLING/4) THAT THE COMMISSION SHOULD NOT CONSIDER THE SMALL DELIVERY

COMMITMENTS OF SMALL QFS WHEN IT CONSIDERS WHAT CREDIT AND SECURITY PROVISIONS ARE APPROPRIATE FOR THEM, RELATIVE TO COMMERCIAL-SCALE SUPPLIERS?

A. Not necessarily. If specific credit and security provisions were too onerous for small-scale developers, the net effect could discourage their investors. The Commission should consider the benefits versus the potential harm given the level of risk exposure for small QFs (e.g., 10 MW and smaller). The total exposure for such projects, when viewed on an aggregate basis, would be dwarfed by all new non-QF development reasonably expected over the next several years.

Q. **DO YOU AGREE WITH MS. WESSLING (PPL/300, WESSLING/8) THAT THE COMMISSION SHOULD NOT MANDATE THE SPECIFIC TYPES AND LEVELS OF SECURITY UTILITIES MAY REQUIRE FOR SMALL QFS?**

A. No. A utility requiring a QF to demonstrate creditworthiness or face default security requirements, if too strict, could cause a proposed QF project to become non-economic. This may be particularly true for smaller projects that may not have significant credit support from their affiliates or parent company. Through this proceeding, the Commission may increase the contract length and facility size eligible for standard rates, but still fail to facilitate QF development in Oregon because of potentially unnecessary and stringent credit and security requirements imposed by the utilities.

Q. SHOULD THE COMMISSION PROHIBIT THE UTILITIES FROM INCLUDING SECURITY PROVISIONS FOR OPERATIONAL RISK IN CONTRACTS WITH SMALL QFS, AS MS. WESSLING SEEMS TO SUGGEST (PPL/300, WESSLING/8)?

A. No. The issue simply involves the level of security requirements that are appropriate for small QFs, given (1) the magnitude of the risk to the utility, (2) the relative risk to ratepayers of large utility-owned resources compared to small QF purchases, and (3) the interest of the Commission in facilitating the development of QFs in Oregon. I recommend in my direct testimony (Staff/400, Morgan/13) that utilities should not be allowed to require a letter of credit or escrow deposit as default security for small QFs.

I offered an alternative to address the perceived increase in operational risk by the utilities — a provision in the power purchase agreement that future payments to the QF would be reduced for a reasonable period of time in the event market prices during the default period exceed the contract price. Other options could likely be determined that appropriately address operational risk for purchases from small QFs, relative to the risk that ratepayers may otherwise experience from utility-owned resources.

Q. DO YOU AGREE WITH MS. WESSLING (PPL/300, WESSLING/9-10) THAT A CONTRACT PROVISION THAT REDUCES FUTURE PAYMENTS TO THE QF FOR A PERIOD OF TIME WOULD INCREASE

THE RISK THAT THE PROJECT WOULD LACK ADEQUATE REVENUES TO REMAIN IN OPERATION?

A. No. The amount that payments are reduced would be specified in the contract, not tied to the market price of replacement power, as Ms. Wessling implies. The penalty amount and duration for payments should be set at a level that would not jeopardize project viability. Further, staff recommends that weather-related production shortfalls not trigger default provisions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1129
WITNESS: J. R. Gonzalez

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 900

Surrebuttal Testimony

October 14, 2004

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

A. My name is J.R. Gonzalez. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97310-1380. I am employed by the Public Utility Commission of Oregon (Commission) as Program Manager of Utility Safety and Reliability.

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes. I prepared Staff/901, consisting of one page, a summary of my educational and work experience.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide surrebuttal testimony on one aspect of the second issue in this proceeding, size threshold for standard avoided cost rates and a standard power purchase agreement.

Size Limit for Connecting to the Distribution System

Q. DO YOU AGREE WITH PACIFICORP WITNESS WIDMER (AT PPL/100, WIDMER/13) THAT "THREE MW ALSO ROUGHLY CORRESPONDS TO THE LEVEL AT WHICH A QF WOULD HAVE TO INTERCONNECT WITH THE TRANSMISSION AS OPPOSED TO DISTRIBUTION SYSTEM"?

A. No. The load-carrying capacity of a power line, considering both the conductor (the size and type of the wire) and voltage, determines what size facility may interconnect to that line. The line may be at distribution or transmission voltage. Typically, projects as large as 8 MW to 10 MW may be interconnected at the 20.8 kV distribution level. At the 12.5 kV distribution level, typically projects sized at 3 MW to 5 MW may interconnect with a distribution circuit that uses a 1/0 copper conductor, and projects 8 MW to 10 MW may interconnect when the distribution circuit uses a 556 steel-reinforced aluminum conductor.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

CASE: UM 1129
WITNESS: J. R. Gonzalez

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Public Utility Commission of Oregon
Administrative Hearings Unit Division

STAFF EXHIBIT 901

Exhibit in Support of Surrebuttal Testimony

DOCKETED

October 14, 2004

WITNESS QUALIFICATION STATEMENT

NAME: J.R. Gonzalez

EMPLOYER: Oregon Public Utility Commission

TITLE: Program Manager, Utility Safety and Reliability

ADDRESS: 550 Capitol Street NE #215
Salem, OR 97301-2551

EDUCATION: Bachelor of Science, Mechanical Engineering (1981)
Portland State University

EXPERIENCE: I have been employed by the Oregon Public Utility Commission since May 2004 as program manager of Utility Safety and Reliability.

Before coming to the PUC, I spent eight years on wireless telecommunications and telemetry programs in Europe, Latin America and Canada.

From 1981 through 1997, I worked at Puget Sound Energy, starting in power generation. Next, I worked in transmission and distribution engineering, then customer programs including conservation, voltage stability and power quality. After that, I worked in transmission and distribution operations. My last position at PSE was manager of the Metering, Distribution Transformers, and Test, Repair and Calibration Department.